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ATTACHMENT 1

R.20-01-007 Track 1A: Reliability Standards and Track 1B: Market Structure and Regulations

WORKSHOP REPORT AND STAFF RECOMMENDATIONS

OCTOBER 2, 2020

California Public Utilities Commission

A digital copy of this report can be found at:
https://www.cpuc.ca.gov/gasplanningoir

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CONTENTS

EXECUTIVE SUMMARY

The California Public Utilities Commission's (CPUC) Energy Division hosted two workshops, on July 7, and July 21, 2020, in Rulemaking (R.) 20-01-007. The workshops sought to provide stakeholders with a common understanding of the Scoping Memo issues, gather information, and seek feedback. Additionally, the workshops were an opportunity for participants to begin to develop possible future scenarios and suggest potential solutions. The intended outcome was for participants and attendees to gain a better understanding of the facts upon which testimony, hearings (if needed), and briefs (if needed) will proceed upon.

This workshop report summarizes the presentations given at both workshops, then provides Energy Division staff's (staff) suggestions.[1] Upon review and consideration of the presentations, discussions at the workshops, and the comments submitted, staff recommends:

- Eliminating all current infrastructure design standards and replacing them with a 1-in-10 peak day design standard for both PG&E and SoCalGas/SDG&E that can be met using a combination of flowing pipeline supply and gas storage;
- Requiring PG&E to provide further details and elaborate on what additional design standard factors beyond weather should be considered;
- That the nine-month criterion in PU Code Section 455.5 be used as a *guideline* for determining the duration after which shareholders begin to absorb a percentage of the cost of repairs for a gas utility's sustained failure to meet minimum transmission system design standards;
- Parties consider whether the supply standards for core customers should be revisited;
- Developing and adopting a reliability definition;
- Relying on data from *California's Fourth Climate Change Assessment* (Fourth Assessment) or the most recent Assessment available in the future;
- Determining that a summer reliability standard does not need to be established at this time;
- Parties make recommendations on slack capacity requirements;
- SoCalGas/SDG&E submit further information of the reliability impact resulting from the proposed North Baja Xpress Expansion project;
- That CAISO submit a proposal that outlines a mechanism for determining the minimum amount of gas supply needed for electric reliability in California and how the CAISO would allocate that gas to electric generators bidding into the market. SoCalGas and PG&E can then provide a response indicating whether the utilities have the capacity to accommodate the identified minimum supply on a firm basis;
- SoCalGas and PG&E submit formal analyses outlining a proposal for a Renewable Balancing Tariff in their respective regions and the associated costs;
- Aligning PG&E's OFO structure with SoCalGas' winter OFO structure;
- Extending SoCalGas' winter OFO penalty structure after the rules expire, pursuant to D.19-05-030, on October 31, 2021.

Additional details surrounding each recommendation can be found in the Staff Recommendations section.

[1] The workshop materials can be found at https://www.cpuc.ca.gov/gasplanningoir/

1 INTRODUCTION

On July 7, and July 21, 2020, Energy Division hosted two workshops for Tracks 1A and 1B, respectively, in R.20-01-007.[2] The purpose of the workshops was to provide stakeholders with a common understanding of the issues, gather information, and seek feedback. Additionally, workshop participants could begin to develop possible future scenarios and suggest potential solutions. The intended outcome for participants and attendees was a better understanding of the facts upon which testimony, hearings (if needed), and briefs (if needed) will proceed.

On July 31, 2020, Administrative Law Judge (ALJ) Tran issued a ruling seeking further clarification and information regarding Tracks 1A and 1B. The ruling contained questions directed to specific parties, and responses were due by August 14, 2020. However, all parties were welcome to provide input in addition to the named respondent(s). Staff considered the comments submitted when drafting the recommendations.

2 BACKGROUND

The majority of the current natural gas reliability standards were established in the CPUC's last comprehensive assessment of the sufficiency of natural gas supplies and infrastructure in California: Rulemaking (R.) 04-01-025. After the 2000-01 energy crisis and in response to Federal Energy Regulatory Commission (FERC) orders, the CPUC determined that, in the long-term, there might not be sufficient natural gas supplies and/or infrastructure to meet the requirements of all California residential and business consumers "unless the Commission takes certain actions in the near future."

The CPUC issued Decision (D.) 06-09-039 in R.04-01-025, which established the current gas reliability standards for infrastructure:

- For Southern California Gas Company (SoCalGas) and San Diego Gas & Electric (SDG&E), one outage event in 35 years for core local transmission customers and one event in 10 years for noncore customers; and
- For Pacific Gas and Electric Company (PG&E), one event in 90 years for core local transmission customers and one event in three years for noncore customers.[3]

The decision also concluded that California's physical infrastructure was sufficient to meet the state's needs at that time. However, a key premise of the decision was that all infrastructure would be functioning as planned and would not be subject to prolonged outages for repair, maintenance, testing, and/or replacement. While the decision did not establish sanctions for utilities that did not meet their reliability standards, it did provide a mechanism for monitoring the adequacy of gas system capacity. Both PG&E and SoCalGas were required to file reports via advice letter every two years, beginning on July 1, 2008, demonstrating that "they hold adequate backbone transmission capacity and have slack capacity consistent with their proposals presented herein."

An additional reliability standard for PG&E was added in September 2019, when the CPUC approved its Gas Transmission & Storage (GT&S) Rate Case. D.19-09-025 adopted the GT&S and PG&E's Natural Gas Storage Strategy (NGSS), which reduces overall storage capacity consistent with the declining need for storage as a price hedge and the increased cost of maintaining storage under new, stricter state regulations. The new reliability standard consisted of 1-in-10 peak day demand for core and electric generators, as

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[2] The Scoping Memo can be found at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M334/K581/334581865.PDF.
[3] PG&E is also held to a one event in two years standard for core and noncore. Additionally, the CPUC approved D.19-09-025, which established a 1-in-10-year standard for noncore customers.

previously allowed by the CPUC in D.06-07-010, along with several new components. Prior to adopting the NGSS, PG&E used core gas in storage on behalf of both core and noncore customers to help balance fluctuations in intraday gas demand, reduce the need for curtailments, and respond to equipment outage-related supply issues. As an outcome of the NGSS, core gas storage was reduced and no longer available for balancing. To compensate for this reduction, PG&E maintains storage capacity designated as Inventory Management and Reserve Capacity.[4]

In recent years, the circumstances that existed in 2004-06 have changed significantly due to increases in domestic natural gas production; the adoption of California's climate goals; and incidents such as the 2010 San Bruno pipeline explosion, the 2015 Aliso Canyon gas leak, and the 2017 rupture of SoCalGas Line 235-2. In response, the CPUC opened R.20-01-007 to update the reliability standards to ensure that they reflect changes in infrastructure availability and policy goals.

3 WORKSHOPS

Both the July 7, 2020, and the July 21, 2020, were held remotely, due to gathering limitations during the Covid-19 pandemic. Staff sent notice of the workshop to the service list of the rulemaking. The public workshop notice was posted on the CPUC's Daily Calendar and website.

The workshops included morning and afternoon sessions, as seen in the agendas in Appendices A and B. In sections 4 and 5 below, the workshop summaries are organized in order of the agenda panels, not in the order of the scoping memo questions.

4 TRACK 1A: RELIABILITY STANDARDS

The Track 1A Workshop on July 7, 2020, covered the following topics:

Scoping Memo Issue 1: What are Southern California Gas Company's (SoCalGas) and Pacific Gas and Electric Company's (PG&E) current system capabilities?

a. Do PG&E and SoCalGas have the requisite gas transmission pipeline and storage capacity to meet the demand for an average day in a one-in-ten cold and dry-hydroelectric year for their respective backbone gas transmission systems and peak day demand for their combined backbone gas transmission and gas storage systems?
b. Do PG&E and SoCalGas have the requisite gas transmission pipeline and storage capacity to meet the local transmission standards adopted in Decision (D.) 06-09-039?
c. How should the Commission respond to a gas utility's sustained failure to meet minimum transmission system design standards?

Scoping Memo Issue 2: Are the existing natural gas reliability standards for infrastructure and supply still adequate? If not, how should they be changed?

a. Should the Commission establish uniform reliability standards for PG&E and SoCalGas, rather than allow the utilities to continue to use different standards?
b. Temperature forecasts for Northern California indicate that between 2018-2035, the average temperature during December and January will be between two to nine percent above the 20-year average. Will the current reliability standards overstate the capacity that gas utilities must maintain?

[4] D.19-09-025, p.35.

c. Gas-fired generators comprise approximately 40 percent of electric supply during the summer months. Temperature trends forecast warmer summers in California; thus, should the Commission establish separate reliability standards for the summer months?

Scoping Memo Issue 3: Should gas utilities maintain a specific amount of slack capacity or additional infrastructure in excess of the amount of backbone transmission and storage capacity necessary to meet the existing one-in-ten cold and dry year reliability standard? If so, how much and under what conditions?

Scoping Memo Issue 4: Will transportation of gas to the planned Energía Costa Azul LNG export facility, owned and operated by an affiliate of SoCalGas, over the proposed expanded North Baja pipeline which is the subject of FERC Docket No. CP20-27, impact reliability and prices in SoCalGas' service territory and beyond? If so, what measures should SoCalGas undertake to assure reliability, and how should such costs be recovered?

4.1 Overview of Existing Natural Gas Reliability Standards

Greg Reisinger, of the Energy Division's Gas Policy and Reliability section, presented on behalf of Energy Division to provide context to Scoping Memo Issue 1. Mr. Reisinger gave an overview of the current reliability framework resulting from the two key decisions in R.04-01-025: D.04-09-022, which focused on reliability of supply; and D.06-09-039, which focused on infrastructure reliability. At the time of these decisions, future interstate gas supply was expected to be limited. Mr. Reisinger presented several key issues concerning the current standards:

- There are multiple measures, but no standard definition of reliability. Mr. Reisinger noted that this appears to be a gas industry trend, as the electric sector does have definitions of reliability.
- The current standards are based more on early 2000s-era gas contracting practices and system capacity combined with generally accepted rules of thumb regarding the acceptable frequency of outages than on quantitative analysis.
- Earlier decisions did not anticipate the large role of gas-fired electric generation in the future.
- There is no clear link between utilities meeting reliability standards and their business performance.
- There has been a major shift in energy policy towards increased decarbonization of the energy portfolio.

Next, Mr. Reisinger covered the 13 infrastructure and supply reliability standards applicable to PG&E and SoCalGas/SDG&E. Then, Mr. Reisinger noted that slack capacity measurement methodologies differ across the gas utilities and that there is no specific slack capacity requirement. He suggested that it may make more sense to use a range rather than a specific number, as changes in demand and supply may change the appropriate slack capacity amount. Mr. Reisinger also recommended that PG&E and SoCalGas/SDG&E calculate slack capacity using their current methodologies as well as those of the other utility.

4.1.1 Summary of Q&A

Mr. Reisinger was asked what he had in mind for a reliability definition. Mr. Reisinger stated that PG&E has a reliability definition in their encyclopedia, and it defines reliability as having the capacity to deliver the amount of gas required to meet customer demand.[5] He recommends an overarching definition of reliability that could cover relevant measures and features of reliability. The next question asked about gas supply and deliverability during earthquakes, to which Mr. Reisinger responded that natural disasters and the like were not considered in reliability on a day-to-day basis. Then, Mr. Reisinger was asked to elaborate on the

[5] The PG&E Encyclopedia is a hard copy publication and is not available for reference online.

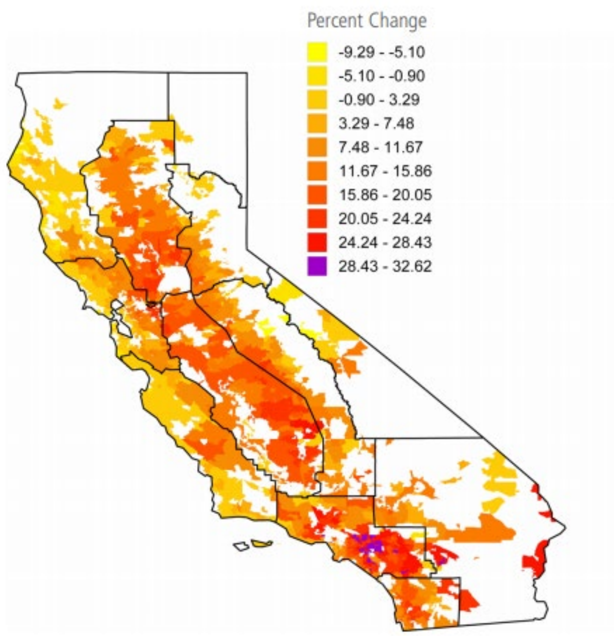
requirement to provide 100-120% of average winter daily demand. He clarified that SoCalGas' requirement to serve that additional capacity only applied to core customer load. Lastly, Mr. Reisinger responded to a question about the history of the gas and electric reliability standards, stating that the changes over the last few decades warrant a rethink about core and noncore customer classes.

4.2 Temperature Projections and Demand Trends

Susan Wilhelm and Cary Garcia presented on behalf of the California Energy Commission (CEC) and provided information for Scoping Memo Issue 2.b. Ms. Wilhelm is the Team Lead of the CEC's Energy-Related Environmental Research team. Ms. Wilhelm presented data and results from California's Fourth Climate Change Assessment, with a focus on the climate projections out to 2100, as well as ongoing research at the CEC.[6] The climate projection methodology was designed to represent daily temperature extremes and the distribution of precipitation. Ms. Wilhelm discussed the projected extreme heat days in a disadvantaged community in Fresno. Currently, the community experiences four extreme "heat days" a year. However, if fossil fuel use remains unchanged, by the end of the century, the community is forecast to experience 51 extreme heat days per year. Those heat days are also expected to become longer and hotter.

Ms. Wilhelm then summarized the findings on Sierra snowpack, which is expected to decline by more than one-third below the historical average by mid-century. A decline in snowpack would mean less hydroelectric generation, which is important in the context of building electrification. She also reported on the work of a fellow researcher who analyzed billions of utility bills and concluded that electricity consumption will rise due to the increased use of air conditioning, especially in inland and Southern California. These findings are shown below in Figure 1.

Figure 1: Projected Changes in Average Annual Household Electricity Consumption



Projected percent changes in average annual household electricity consumption in 2080-2099 for RCP 8.5 relative to a 2000-2015 baseline.
Data source: Auffhammer, 2018.

The presentation moved onto discussing the projected minimum temperatures through 2079 in downtown Los Angeles. Ms. Wilhelm noted that minimum temperatures are projected to increase through 2079, with

[6] California's Fourth Climate Change Assessment can be found here: https://www.climateassessment.ca.gov/

the confidence intervals widening in later years. This means there is less certainty and more variability in the forecasts.

In closing, Ms. Wilhelm emphasized that climate projections are not weather forecasts and that the probabilistic interpretation of these models is complex.

Next, Mr. Garcia gave an overview of how the CEC uses climate change forecasts in their natural gas end-use forecasts. He is the lead forecaster of the CEC's Demand Forecasting Office, which prepares residential and commercial natural gas forecasts. To do this, the CEC has consumption models with weather parameters (heating and cooling degree days) that tease out the effects of temperature. CEC staff use a 30-year normal for their projections. CEC staff also selected a likely and a hot scenario to model mid- and high demand cases. Then, a second model is run with the mid- and high demand cases to represent climate change impacts. The differences between the 30-year normal model and mid- and high cases is their climate change adjustment.

The results of the model—which forecasts annual, rather than hourly, average impacts—show that climate change results in a 1.6 to 1.8 percent reduction in gas use in 2030. The declines in residential demand accounts for about 80 percent of that decrease.

4.2.1 Summary of Q&A

During the question period, Mr. Garcia clarified that their analysis is not on an hourly basis; rather the CEC uses aggregated data from the utilities.

4.3 Can the Reliability Standards Be Met? Are They Still Adequate?

Energy Division invited a panel of five speakers to present and address the current reliability standards. The speakers were representatives from PG&E, SoCalGas, San Diego Gas & Electric (SDG&E), Center for Energy Efficiency and Renewable Technologies (CEERT), Utility Consumers' Action Network (UCAN), and Indicated Shippers (IS).

4.3.1 PG&E

Roger Graham, Rick Brown, and Richard Beauregard presented on behalf of PG&E's Gas Operations Division. Mr. Graham is a Senior Manager in Product Management, Mr. Brown is a Senior Manager in Gas System Planning, and Mr. Beauregard is a Manager in Gas Backbone Planning. Mr. Graham began by stating that PG&E's total receipt capacity is 3,055 million cubic feet per day (MMcfd). PG&E is phasing out two of their utility-owned storage fields, Los Medanos and Pleasant Creek.

To address Scoping Memo Issue 1.a, Mr. Graham explained that PG&E is operating under the backbone capacity utilization standard from D.06-09-039 and the peak day standard from D.19-09-025. PG&E proposed the latter standard because it did not believe the 1-in-2 standard was reliable enough. Mr. Graham stated that the most difficult demand to predict is electric generation demand because there is an economic component based on gas prices. To arrive at the electric generation forecast for the 1-in-10 peak day standard, PG&E used the 95th percentile of daily winter demand (November-March) from 2016 to 2020. Mr. Graham presented Figure 2 (below) and stated that PG&E's capacity utilization is reasonably low, with slack capacity that can be used for storage injection and to cover for outages. For the next three years, PG&E is forecasting an excess of supply.

Next, Mr. Brown addressed Scoping Memo Issue 1.b. by stating that all of PG&E's local transmission and distribution systems meet the abnormal peak day (1-in-90) and cold winter day (1-in-2) design standards established in D.06-09-039.

Figure 2: PG&E Backbone Capacity Utilization (Slide 48)[7]

2021-2030 (MMCF/D)

Line No.	Year	Average Demand(a)	1-in-10 Cold and Dry Year Demand(a)	Backbone Receipt Capacity	Capacity Utilization Cold and Dry Year Demand
1	2021	2,013	2,089	3,055	68%
2	2022	1,998	2,061	3,055	67%
3	2023	1,984	2,044	3,055	67%
4	2024	1,833	1,893	3,055	62%
5	2025	1,711	1,772	3,055	58%
6	2026	1,690	1,750	3,055	57%
7	2027	1,667	1,725	3,055	56%
8	2028	1,664	1,724	3,055	56%
9	2029	1,649	1,708	3,055	56%
10	2030	1,629	1,688	3,055	55%

Notes:
(a) Average Demands and 1-in-10 Cold and Dry Year Demands are based on preliminary 2020 California Gas Report numbers. Off-system contracts are reduced in 2023 and 2024 and are excluded entirely in 2025-2030 to reflect only PG&E's currently booked off-system contracts for those years.

4.3.2 SoCalGas/SDG&E

Jonathan Peress, Senior Director of Regulatory Affairs, and David Bisi, Manager of Gas Transmission Planning, presented on behalf of SoCalGas/SDG&E. First, Mr. Peress covered the distinction between core and noncore customers, emphasizing that noncore intraday variability is increasingly more volatile and less predictable, especially for electric generation customers.[8] When noncore customers schedule supply into the system, the supply arrives in steady hourly quantities. However, many noncore customers, particularly electric generators, burn far more than the hourly supply coming into the system during the relatively short period when they use gas. Mr. Peress stated that the rate of ramping has been steadily increased over the last few years and that it has increased by as much as 20 percent in the last two years. Meeting electric generators' ramping needs requires the use of system assets such as storage and linepack. However, Mr. Peress asserted that the majority of the system costs, including the cost for services noncore uses, are allocated to core customers.

Mr. Bisi provided input into Scoping Memo Issues 1.a-c and 2. He stated that the SoCalGas and SDG&E systems were designed to use pipeline and storage supplies, not one or the other. Then, Mr. Bisi stated that SoCalGas/SDG&E's current receipt capacity, as of the workshop date, is 2,965 MMcfd; this figure excludes 210 MMcfd for California producers. Mr. Bisi maintained that SoCalGas/SDG&E can meet the 1-in-35 peak day demand of 3,490 MMcfd with the 2,965 MMcfd of interstate pipeline receipt capacity, 60 MMcfd of California production, and an estimated 1,105 MMcfd of December-January storage withdrawal capacity. However, currently, SoCalGas/SDG&E is not able to meet the 1-in-10 cold day demand of 4.9 Bcf. Mr. Bisi pointed to pipeline outages and degraded withdrawal capacity due to well inspections, storage operating limitations, and the holding of only enough storage inventory to meet core reliability needs as the reasons

[7] The 1-in-10 Cold and Dry Year Demand referenced in this table is for an average day in a cold and dry year.

[8] Generally speaking. core customers include all residential customers and commercial and industrial customers with an average usage less than 20,800 therms per month. Noncore customers are those whose average usage exceeds 20,800 therms per month. Noncore customers assume gas procurement responsibilities and receive gas transportation service from the utility under firm or interruptible intrastate transmission arrangements.

the reliability standard cannot be met. At 90 percent receipt capacity utilization and under limited storage assumptions, their system can supply 3.4 billion cubic feet per day (Bcfd) without Aliso Canyon and 3.8 Bcfd with Aliso Canyon.

Mr. Bisi projected that between 2025 and 2030, SoCalGas' Northern System would be restored to 1,590 MMcfd and that the storage fields would be restored to their former withdrawal capacities. With those changes, the SoCalGas/SDG&E system would be able to serve approximately 6 Bcfd. The forecasts are shown in Figure 3.

Figure 3: Forecasted Demand

	1-in-35 Year Peak Day Demand (MMCFD)				1-in-10 Year Cold Day Demand (MMCFD)			
Operating Year	Core	Noncore C&I	EG	**Total**	Core	Noncore C&I	EG	**Total**
2025/26	3,314	0	0	**3,314**	3,113	628	977	**4,718**
2030/31	3,169	0	0	**3,169**	2,972	604	941	**4,517**
2035/36	3,162	0	0	**3,162**	2,965	597	939	**4,501**

In their responses to Scoping Memo 1.c, regarding the appropriate CPUC response to a sustained failure to meet minimum transmission system design standards, Mr. Bisi stated that failures should be considered in the context of system and operating conditions. Circumstances such as operational restrictions imposed by regulatory bodies and other regulatory challenges are long-lead items, while reliability standards can change immediately.

Mr. Bisi responded to Scoping Memo Issue 2, suggesting that reliability standards should be based on reliability needs, not assets that will be retained or retired. He stated that the 1-in-35 peak standard assumptions are unrealistic because it assumes that all noncore customers are curtailed. He asserted that it is difficult to curtail all noncore customers and that some noncore customers should be reclassified as core. SoCalGas/SDG&E recommended redefining noncore customers and revising the 1-in-35 peak day standard to include some customers that are currently classified as noncore, which would then eliminate the need for a 1-in-10 cold day standard.

In closing, Mr. Bisi advocated for different design standards in the PG&E and SoCalGas/SDG&E systems due to the differences in their infrastructure and customer base.

4.3.3 CEERT[9]

Jim Caldwell presented on behalf of the Center for Energy Efficiency and Renewable Technologies (CEERT), where he is Senior Technical Consultant. Mr. Caldwell stated that the existing reliability standards were created when there was a commodity shortage. Next, he discussed a loss of load event experienced by up to 5,000 customers in Ashland, Oregon. The cause was pressure loss due to human error. It took six days and approximately 10,000 person-hours to restore the system. Mr. Caldwell warned against allowing a similar event to occur in a larger area. With the extensive corrosion of the desert pipelines, Aliso Canyon leak, and other events leaving the SoCalGas system short of slack capacity, Mr. Caldwell claimed that the avoidance of any loss of load on the electric or gas system is attributable to luck. Rather, the impact has been a financial impact due to higher gas prices. Mr. Caldwell provided an example of June 3, 2020, when

[9] CEERT's presentation did not include any slides.

electricity prices were $150/MWh at approximately 39 gigawatts (GW) of load on the electric system; he believes this was a result of a disruption in gas supply.

Mr. Caldwell suggested that more analysis needs to be done on the near misses on the system. Additionally, he strongly pushed for reduced electric generation dependence on gas, citing that the technical and economic capabilities to replace gas are available. He ended with suggestions to have multiple receipt points to increase reliability, achieve more demand response, and to plan for a policy future with low carbon towards the year 2045.

4.3.4 UCAN

Dr. Eric Woychik presented on behalf of the Utility Consumers Action Network (UCAN), which is a non-profit focused on protecting ratepayers in the metropolitan San Diego area. Dr. Woychik made seven points. First, he stated that the most important point was that gas demand needs to be reduced to meet existing gas infrastructure, not the other way around. Second, he stated that the gas utilities should be required to file infrastructure plans that explain capital and operations and maintenance (O&M) spending for safety and reliability—this information is needed to answer the questions in the Scoping Memo. Third, UCAN believes gas line extension allowances and gas utility incentive mechanisms should be removed as soon as possible, because the former are no longer necessary, and the latter allow utilities to benefit from events such as operational flow orders (OFOs). Fourth, UCAN recommended that gas utilities should focus on how and where gas demand is reduced, so gas infrastructure can be retired. Additionally, all new single-family residential gas hookups should be prohibited in the SDG&E service territory. Fifth, Dr. Woychik suggested that California's core/noncore model needs reform, as it has been the same model since 1985. Sixth, he recommended that the retirement of gas-fired electric generators should be directly coupled with new battery storage. Finally, Dr. Woychik recommended that the CPUC should only authorize gas infrastructure essential for safety and reliability or risk stranded costs.

4.3.5 Indicated Shippers

Maurice Brubaker—President of Brubaker & Associates, Inc.—presented on behalf of Indicated Shippers, which represents large, noncore end users of gas. He posed the question of whether the level of reliability experienced by customers is acceptable to the consumers and the regulators. To maintain acceptable reliability going forward, Mr. Brubaker suggested that utilities perform probabilistic modeling of future conditions with a special emphasis on asset management. Asset management entails maintaining key components of the system in working order, maintaining adequate records, conducting effective preventative maintenance programs, and avoiding large capital outlays unless necessary, as they may have a limited lifespan. If the current reliability of service is not adequate, it is likely because of outages resulting from inadequate asset management. Mr. Brubaker stated that new gas infrastructure in Southern California should not be built until the future of Aliso Canyon is known.

In response to Scoping Memo Issue 2.a., Mr. Brubaker explained that the customer experience in the PG&E and SoCalGas/SDG&E systems should be the same, but the design standards to achieve that experience may be different.

He then addressed Scoping Memo Issue 1.c. by suggesting that more than occasional outages should receive a strong regulatory response. This can be done by "putting dollar signs on the problem" and either requiring utilities to share in the cost of repair or reducing the utility's return on equity. Mr. Brubaker discouraged awarding superior performance as it could encourage over-building.

4.3.6 Summary of Q&A

No substantial items to report.

4.4 Is a Summer Reliability Standard Needed?

After the lunch break, a panel of electricity market and generation experts shared their views on whether the CPUC should establish separate reliability standards for the summer. The speakers were representatives from the California Independent System Operator (CAISO), Southern California Generation Coalition (SCGC), and Crossborder Energy.

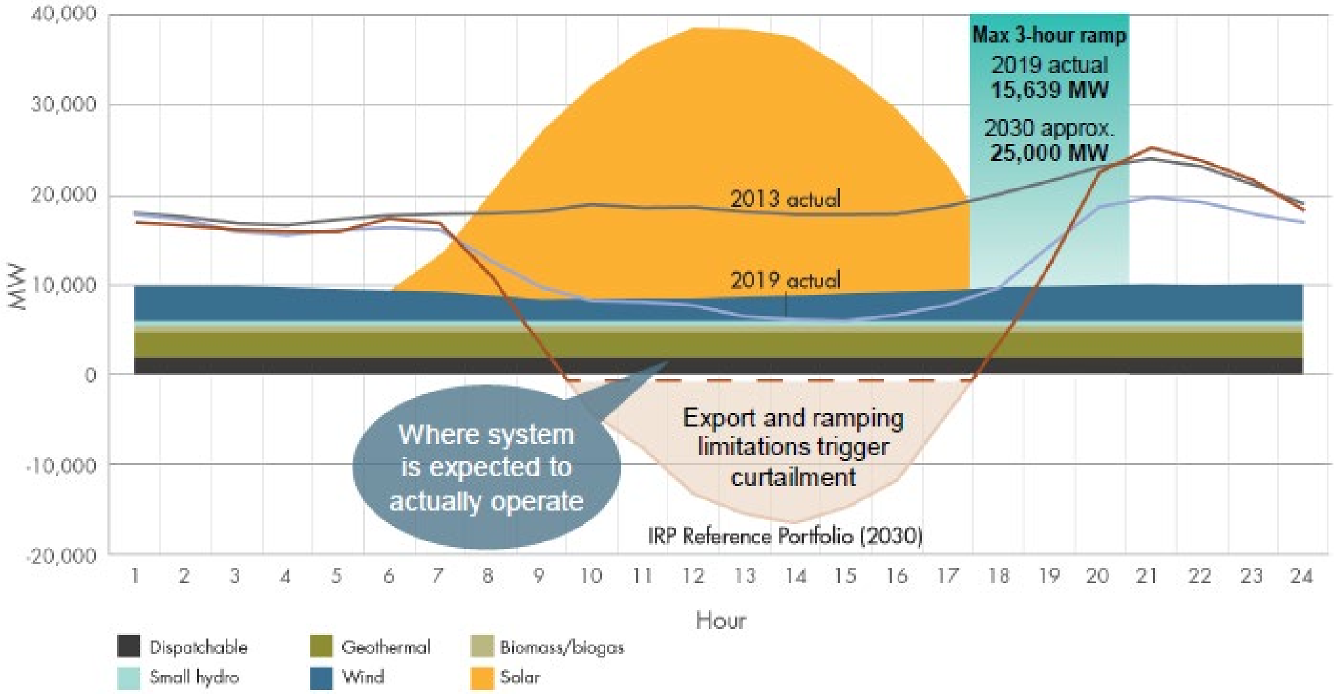
4.4.1 CAISO

Delphine Hou presented on behalf of CAISO, where she is Director of California Regulatory Affairs. Ms. Hou stated that while the summer is important to CAISO, it is also important to consider *all* seasons and *all* hours of need. Data can be aggregated into averages, but CAISO focuses on the story within an hour. Additionally, load shapes are changing, and the future load shape may be different and more volatile in each hour.

Ms. Hou urged that considerations be given to noncore gas demand in the middle of winter and increased renewable energy supply and penetration. Figure 4 was shared to depict CAISO's representation of the net load curve over the last few years. In the past, the blue "2013 actual" line appeared to curve much more, but the magnitude of the y-axis in today's scale, makes it almost appear like a flat line in comparison to current data. The figure includes a model of the CPUC's recently adopted Integrated Resource Plan (IRP) portfolio, which includes large-scale solar penetration. Ms. Hou asked, "What will be the balancing resource then?" She stated that CAISO needs a roadmap of gas resources in the future, which will be shaped by factors such as Senate Bill 100 and the IRP, in order to understand how to operate the system of the future.

Next, Ms. Hou covered electric supply on January 1, 2019. With a ramp of 15,000 MW in three hours, this was the maximum ramp of 2019—and it occurred on a low demand day in the winter. Then, she pointed to the week of January 13-18, 2019 as an example of multiple days of low solar production. A concern within CAISO is the ability to charge batteries despite multiple days of cloud coverage.
Ms. Hou ended with a discussion on hourly variability within each day from January 14 to 16 and May 21 to 28, 2019. This comparison highlighted the high degree of generation resource variability that occurs throughout a day whether there is typical solar generation or low solar generation that day.

Figure 4: Actual and Projected Maximum Three-Hour Ramp



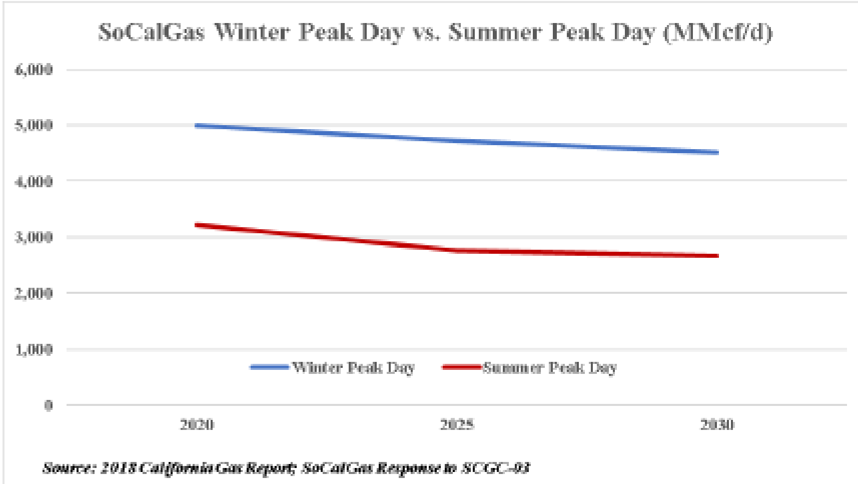
4.4.2 Electric Generators

Norman Pedersen, an attorney with Hanna and Morton, LLP, presented on behalf of SCGC, and Tom Beach, a Principal Consultant at Crossborder Energy, presented on behalf of Crossborder Energy, SCGC, Vistra Energy, Middle River Power, and Calpine. Mr. Pedersen began by stating that summer reliability standards are not necessary. He showed daily total customer demand data for SoCalGas and PG&E from April 2014 through December 2019 to highlight that both systems are winter peaking systems. Mr. Pedersen suggested that the "noise" of daily demand can be eliminated by looking at average summer and winter day demands. Using this method, he presented average summer and winter demand in SoCalGas and PG&E territories, pointing out that the differential between the average summer and average winter gas demand has increased over the last several years.

The 2018 California Gas Report peak day forecast for SoCalGas winter 2019-20 was 35 percent higher than summer 2020, and for PG&E winter 2019-20 was 56 percent higher than summer 2020 demand. Mr. Pedersen then shared data request responses from the utilities, which showed a continued differential between winter and summer demand, as seen in Figure 5. Mr. Pedersen advocated for the 2020 version of the California Gas Report, which had not yet been released at the time of the workshop, to be included in the record of the proceeding.[10] In conclusion, Mr. Pedersen stated that a system designed to meet winter peak day demand will continue to be sufficient to meet summer peak day demand.

[10] The 2020 California Gas Report was released on August 24, 2020, and can be found here: https://www.pge.com/pipeline/library/regulatory/cgr/index.page.

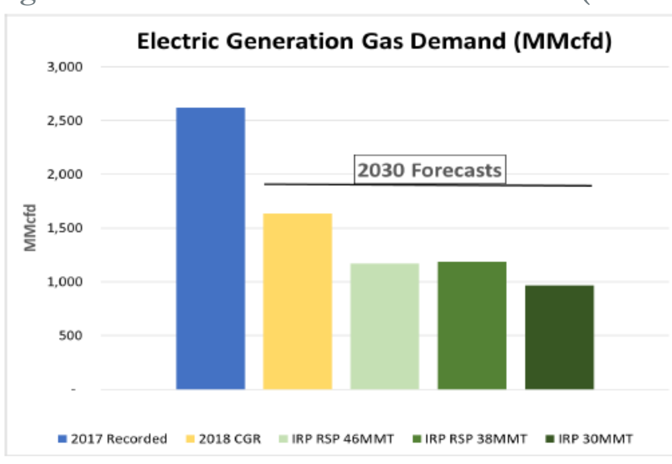
Figure 5: SoCalGas Winter Peak Day vs. Summer Peak Day (MMcfd)



Mr. Beach began his part of the presentation by reminding attendees that the current reliability standards already consider summer because the standard calls for 1-in-10 dry-hydroelectric years, and hydro conditions are a key driver of summer electric generation demand. He recognized that there have been steps taken recently to increase gas balancing and reserve services in PG&E's Gas Transmission & Storage (GT&S) Rate Case, D.19-09-025 and SoCalGas' Triennial Cost Allocation Proceeding (TCAP), D.20-02-045.

Mr. Beach pointed to the price spikes discussed by Mr. Caldwell and stated that they were not due to inadequate reliability standards; rather, they were due to inadequate infrastructure, and the gas utilities' inability to comply with the existing reliability standards. Aside from July and August 2018, price spikes have also occurred in the winter. Mr. Beach's second-to-last slide, shown in Figure 6, compared gas demand for electric generation in 2017 to the 2030 IRP forecasts, which show a significant decrease. Then, he reiterated Mr. Pedersen's statement that a summer reliability standard is not needed.

Figure 6: Electric Generation Gas Demand (MMcfd)



4.4.3 Summary of Q&A

A participant asked Mr. Pederson if he had concerns about supplying gas generators quickly to meet the summer ramp. Mr. Pedersen noted that this topic was more relevant for the July 21 workshop and stated that there is a concern about the increasing ramp in gas demand by electric generators. However, SCGC did not believe a summer reliability standard was needed. Mr. Beach added that the recently approved Integrated

Resource Plan should help alleviate the ramping problem because it included a significant amount of battery storage. In response to a question about reclassifying a portion of electric generators as core customers, Mr. Beach stated he does not think it is a viable solution because the competitive electric market relies on a competitive market for fuel as well. On the other hand, other types of noncore customers, such as hospitals, may benefit from being core customers. The participant then asked if a 20,000 MW ramping need was large. Ms. Hou confirmed that a 15,000 MW ramp, as shown in her slides, is large, and that there are localized issues, such as monsoonal weather patterns in Southern California during the summer. During those moments, there could be large areas of cloud cover and drops in solar production.

4.5 Slack Capacity: Prudent or Wasteful?

Energy Division invited a panel of three speakers to discuss the slack capacity margins established in D.06-09-039 and the authorization of the Reserve Capacity service adopted in D.19-09-025 for PG&E. The speakers were representatives from PG&E, SoCalGas/SDG&E, and SCGC/IS.

4.5.1 PG&E

Mr. Graham began by saying that PG&E still agrees with the slack capacity requirements established in D.06-09-039. He stated that the current requirements work well for PG&E and that PG&E is looking for ways to retire infrastructure and lower its capacity because the utility has a substantial capacity surplus forecasted in the future. Furthermore, a more precise standard would be more complex and contentious. Mr. Graham added that it is also important that the multiple market participants bring enough supply onto the system. He noted that when PG&E analyzed variability on its system, there was a much larger ramp in the winter than the summer.

Mr. Brown added that other factors, such as confidence interval levels for the reliability standards and minimum design pressure, need to be considered along with the temperature recurrence intervals (such as a 1-in-35 standard). Mr. Graham stated that the PG&E and SoCalGas systems are fundamentally different.

4.5.2 SoCalGas/SDG&E

Mr. Bisi presented on behalf of SoCalGas/SDG&E. He noted that slack capacity does not include storage capacity. He explained that the calculation of slack capacity that SoCalGas/SDG&E submits to the CPUC is based off a forecast of demand and receipt capacity, noting that demand is an annual average and that receipt capacity is not representative of actual gas supply scheduled by customers. Mr. Bisi presented Figure 7: from slide 119, which assumes that SoCalGas' Northern System returns to 1,590 MMcfd in the 2025-2035 forecasts.

Figure 7: Reserve Margin Forecast

Year	Average Daily Demand (MMCFD)	Receipt Capacity (MMCFD)	Reserve Margin (%)
2020	2,679	3,175	19%
2025	2,512	3,775	50%
2030	2,388	3,775	58%
2035	2,390	3,775	58%

Next, Mr. Bisi presented a slide that included the following questions:

- What is the intended purpose of the slack capacity?
- When and how should the slack capacity be maintained?
- Should storage be included in slack capacity, and who will maintain the storage?

- Where will the funding come from, and will there be GRC[11] support to maintain slack capacity?

Mr. Bisi stated that D.06-09-039 did not establish slack capacity percentages to maintain. Then, he suggested that one way to quantify slack capacity is to first determine an acceptable cost resulting from insufficient slack capacity. The cost could become the annual revenue requirement for system improvement. The utility would then find improvements that increase slack capacity at this cost or less and be able to recover those costs.

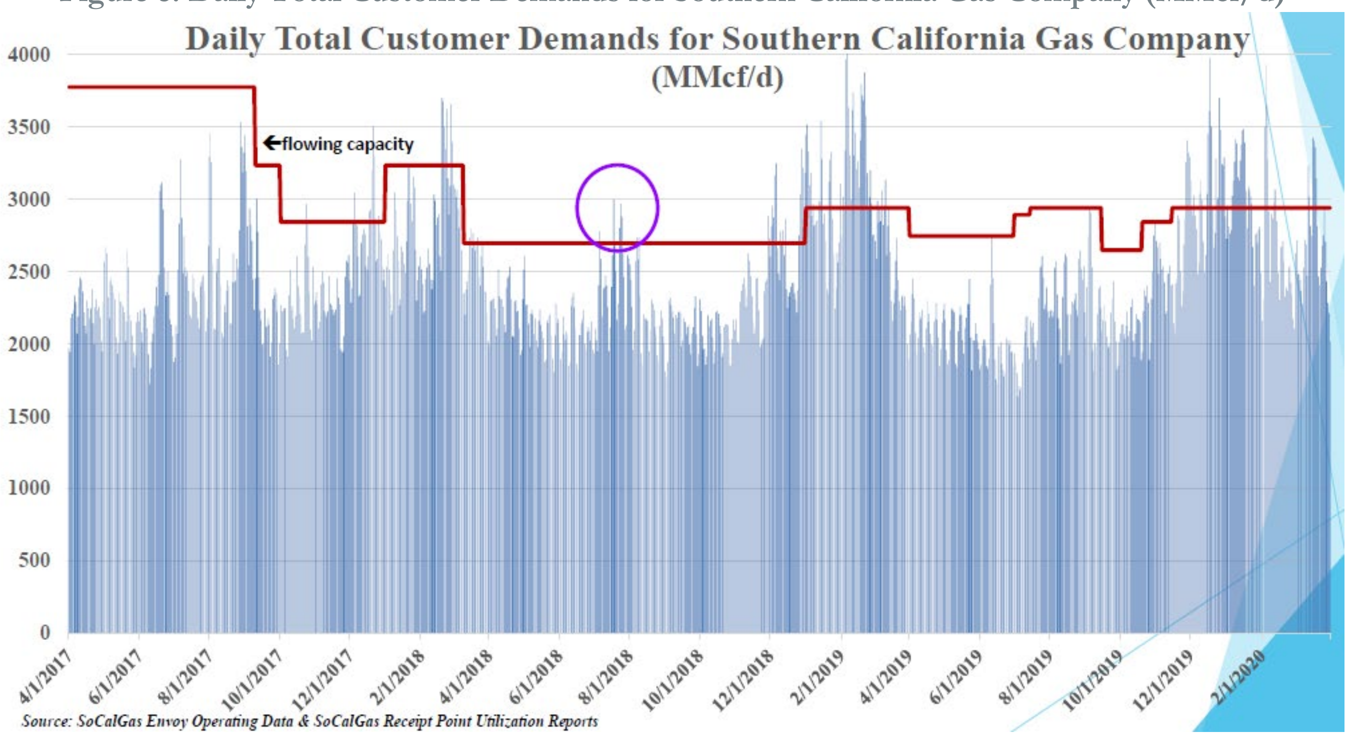
4.5.3 SCGC and IS

Catherine Yap, of Barkovich and Yap, Inc., presented on behalf of both SCGC and IS. She started by noting that the current definition of slack capacity does not include storage; however, the Scoping Memo asked about the combined transmission and storage systems.

Ms. Yap explained that slack capacity is important because it enables gas-on-gas competition by ensuring pipeline or storage maintenance does not interfere with gas competition. On the SoCalGas system, slack capacity has been reduced by maintenance activities, and she believes that improved access to storage withdrawals would compensate for that reduced slack capacity.

She presented data on SoCalGas and PG&E customer demand from April 2013 through December 2019, indicating that winter 2013-14 was very cold. Ms. Yap stated that historically, usage is highly variable, therefore adequate capacity is needed to meet demand during extreme weather days and to avoid price spikes. She also presented Figure 8, which includes a circle around several days in July 2018 when demand exceeded available flowing supplies in the SoCalGas service territory and both gas and electric prices spiked. During these dates, demand on the PG&E system also exceeded available flowing supplies, but PG&E Citygate prices did not see exorbitant increases. Ms. Yap explained that during this these dates, PG&E had unconstrained access to storage. On the other hand, SoCalGas had "severe" constraints and only Gas Acquisition and the System Operator had access to storage.

Figure 8: Daily Total Customer Demands for Southern California Gas Company (MMcf/d)



[11] GRC is an acronym for General Rate Case.

Ms. Yap stated that SoCalGas' Gas Acquisition department sold approximately 3.4 million dekatherms (Dth) of gas from core storage at an average price of $12.19/Dth in July 2018, which is allowed under the Gas Cost Incentive Mechanism (GCIM). She concluded with an explanation that all electric customers in the state paid higher electricity prices due to the higher SoCal Citygate prices.

4.5.4 Summary of Q&A

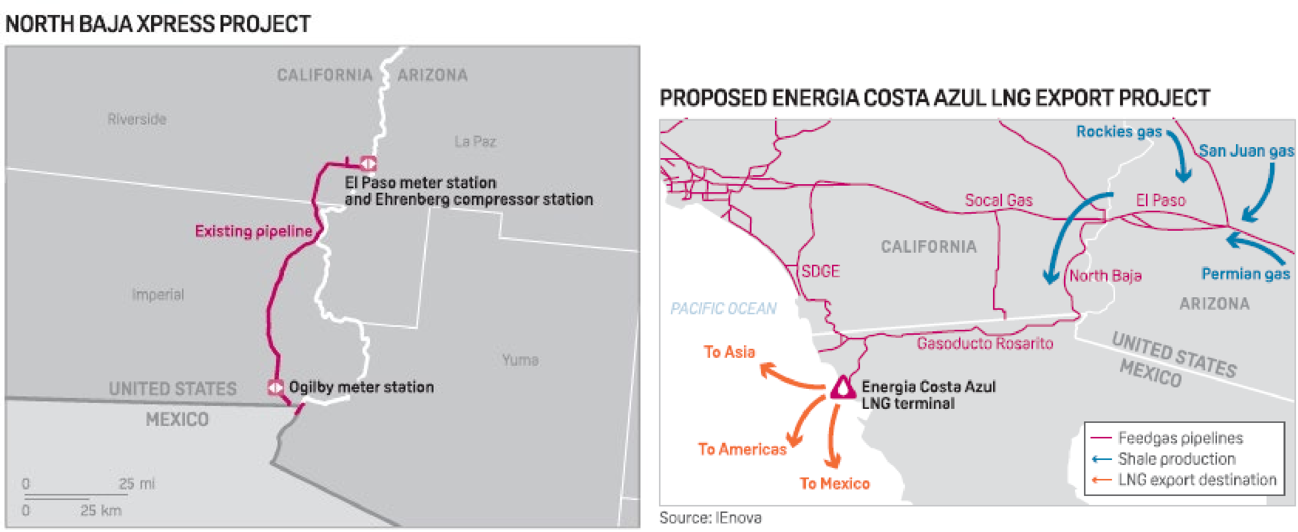
There were two questions for this panel. The first was for PG&E about their ramping period. Mr. Graham responded that their residential and small commercial ramps begin around 5:00 AM. The participant pointed to slide 89, which shows that solar generation begins around 8:00 AM, after the thermal load need. He asked Mr. Graham if PG&E has looked at the impact to the thermal load if heating was electrified, to which Mr. Brown responded that PG&E has not looked at that yet. Mr. Graham noted that replacing heating needs with heat pumps with coefficients of performance values of two or higher might provide the same efficiency as gas-fired appliances. The participant suggested that this analysis should be considered in the proceeding.

The second questioner asked if SoCalGas profits from gas sold under the GCIM. Mr. Bisi responded that he was unaware of SoCalGas' Gas Acquisition activities. Ms. Yap noted that those activities are legitimate under the GCIM mechanism, and the majority of the returns were generated from the secondary market.

4.6 Proposed North Baja Xpress Expansion Project, FERC Docket CP20-27: Impacts on California

Paul Borkovich presented on behalf of SoCalGas/SDG&E where he is the Capacity Support Manager. He stated that the El Paso Natural Gas (EPNG) South Mainline is the source of supply for the North Baja Xpress project, which is one of the pipeline projects proposed to serve gas requirements in Mexico. The Permian Basin is the primary supply source for the South Mainline, but the Rockies and San Juan Basin can also provide supplies to North Baja. See Figure 9 for a map of the region being discussed.

Figure 9: Maps of the North Baja Xpress Expansion Project and Proposed Energia Costa Azul LNG Export Project



Currently, the EPNG delivery capacity to the Ehrenberg receipt point on the California-Arizona border is 2.3 Bcfd. SoCalGas' takeaway with no maintenance is 1.2 Bcfd, and North Baja's is 0.51 Bcfd. The North Baja Xpress would take away an additional 0.48 Bcfd. Mr. Borkovich explained that the System Operator is obligated to have gas supply delivered to the Southern System to meet minimum flow requirements when not enough gas buyers choose to deliver to non-Southern System receipt points.

Next, he stated that the System Operator's mission is to maintain system operations and integrity while minimizing costs at all times, as stated in Rule No. 41. The System Operator does not expect a need to acquire upstream firm capacity rights on the EPNG system to meet Southern System minimum flow requirements. Mr. Borkovich explained that SoCalGas mostly serves Southern System loads with supply from Ehrenberg and Otay Mesa. Additionally, there are four tools used to maintain Southern System reliability, as ratified in D.16-07-015.

Mr. Borkovich maintained that in the North-South Project Application, SoCalGas/SDG&E sought CPUC approval to construct a pipeline and system enhancements to improve the reliability of gas supplies in the Southern System and to increase Northern System receipt point capacity. In D.16-07-025, the CPUC found that the existing tools were reasonable alternatives to the North-South project.

Mr. Borkovich made four points about the current situation. First, gas supply receipts to the Southern System have exceeded the minimum flow requirement every day for the past two storage cycles. Secondly, the biggest impediment to higher receipts is low gas demand on the Southern System. Third, the Gas Acquisition Department continues to perform under the Memorandum in Lieu of Contract (MILC) to meet core's share of the minimum flow requirement. Lastly, SoCalGas expects this situation to continue until gas demand balances with available supply on the EPNG South Mainline system.

He noted that there were no Southern System Reliability purchases from April 1, 2018, to March 31, 2020. On slides 159-161, he shared charts that were presented during the SoCalGas Customer Forum, which showed up to 1.2 Bcf received on certain days. Slides 160-161 contained a chart of maximum Southern System receipts, which did not exceed 1 Bcf from April 2018 through March 2020.

4.6.1 Summary of Q&A

A question was received asking how the mismatch between delivery and takeaway capacity at Ehrenberg occurred. Mr. Borkovich responded that a lot of it is likely due to lower electric generation demand and customer demand overall. Next, a CPUC staffer asked about how North Baja deliveries would impact the Southern System minimum and deliveries, specifically how much SoCalGas would have to buy to deliver on the Southern System. He stated that there is concern about losing capacity at the border. Mr. Borkovich responded that the North Baja projects are trying to serve the baseload requirements in Mexico,[12] and if SoCalGas needs to buy gas, they are certain they will be able to find the gas. Additionally, the gas would likely be above market costs, and SoCalGas will incur costs as they have in the past.

Next, a participant inquired about the current status of the North Baja pipeline with FERC. Mr. Borkovich stated that he did not know. CPUC Attorney Mr. Bromson responded that the application is still being considered at the FERC.

Lastly, Mr. Pedersen asked about the current EPNG Ehrenberg capacity of 2.3 Bcfd, while SoCalGas has a takeaway capacity of 1.2 Bcfd. Mr. Borkovich stated he believes that the 2.3 Bcfd includes flow from Line

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[12] This assertion is contrary to the Abbreviated Application For a Certificate of Public Convenience Necessity by North Baja Pipeline, LLC ("Application"), FERC Docket No. CP20-27, p. 4, which stated that "the upgrades and modifications being requested in the instant Application will create capacity to provide transportation of feed gas for Sempra LNG and IEnova's proposed Energía Costa Azul LNG export plant located at its existing ECA terminal in Ensenada, Baja California, Mexico" rather than for "baseload requirements in Mexico."

6903, which comes from the Mojave and Kern River systems, and the Havasu crossover expansion, as well as other expansions to serve customers east of California.

4.7 Summary of Final Q&A

At the end of the day, there was a final question-and-answer period in which participants could ask questions on any of the day's topics. The first question asked if standards will look at future usage and consider renewable gas and blending limits. Mr. Reisinger stated that he was unsure, but he suspects that the standards are independent of the product in the pipelines.

Then, Mr. Woychik asked how reduced demand for gas and infrastructure should be handled to ensure gas-on-gas competition, whether an approach to consider hedging against gas price spikes should be considered, and what measures can be taken as gas demand is reduced to ensure excessive price spikes. Ms. Yap stated that she did not agree that reducing demand for natural gas means gas-on-gas competition is eliminated. Mr. Woychik clarified that he was asking about other ways to deal with mitigating constraints, other than gas-on-gas competition. Ms. Yap responded that competition doesn't have to be eliminated, as there is competition in the supply basin. Furthermore, as long as there is demand for gas at the Citygate, there will be a market and suppliers, and there will be competition among suppliers. There may be a situation where supplies have to be brought in through Ehrenberg and the gas has to be brought in from the Permian basin, but there is still competition among suppliers in the Permian basin. Ms. Yap concluded that if the amount of gas that Gas Acquisition has to buy shrinks, it does not mean there is less competition.

Mr. Woychik followed up with a question regarding what should be done if Aliso Canyon is shut down. Ms. Yap stated that if Aliso Canyon is shut down, there will be a serious capacity shortage on the SoCalGas system and a situation similar to summer 2018 would occur again in both the winter and summer. Ms. Yap stated that based on the 2018 experience, she would expect price spikes and possible curtailment unless capacity can be added.

Next, a participant commented that staff should look at the cost of new infrastructure as gas use declines. The next question asked Mr. Caldwell about the gas needed to replace Diablo Canyon and whether it was wise to "put all of our eggs in one energy basket." Mr. Caldwell said no and that replacing Diablo Canyon with natural gas is not rational.

Another participant asked if another category should be created for electric generators, if they are not considered core. Ms. Yap commented that her comparison shows the value of storage and its relationship to the market. She added that noncore's access to storage is essential and should be considered carefully by Energy Division staff.

The last question asked the utilities for their once-through-cooling (OTC) power plant assumptions. Mr. Bisi stated that any OTC plant that is expected to be out of service is removed from the SoCalGas forecast. Mr. Graham stated that he believes the same is true for PG&E.

5 TRACK 1B: MARKET STRUCTURE AND REGULATIONS

The Track 1B Workshop on July 21, 2020, covered the following topics:

Scoping Memo Issue 1: Should the Commission consider whether potential fluctuations in natural gas demand combined with potentially insufficient firm interstate gas pipeline contracts held by California customers could pose risks to interstate pipeline capacity services?

a. What measures, if any, can be taken to ensure interstate pipeline transportation capacity reliability?

b. What measures, if any, can be taken to ensure that gas needs of electric generators are met during hourly and intraday fluctuations?
c. What measures, if any, can be taken to ensure that gas needs of electric generators are met during multiple days of low renewable generation?

Scoping Memo Issue 2: During 2017 and 2018, the higher than average gas prices at SoCal Citygate caused the price of wholesale electricity to significantly increase. Should the Commission establish contract or tariff terms and conditions or new rules to attempt to decrease the risk of electricity price volatility caused by potential gas supply issues? If so, what terms, conditions or new rules should be considered?

Scoping Memo Issue 3: Should pipeline operating procedures, such as those for curtailments and operational flow orders, be uniform across the state? Would there be any market and reliability impacts if pipeline operating procedures were not uniform?

5.1 Gas Demand Fluctuations and Interstate Capacity Contracts: Risks and Resolutions

5.1.1 Wood Mackenzie and E3

Eric Eyberg presented on behalf of Wood Mackenzie and Arne Olson represented E3. Mr. Olson, who is a Partner at E3, spoke about resource-related trends observed by E3 over the past several years and trends predicted for the near future. E3 expects demand for power generation to continue to grow over the next five to 10 years across the western region. Approximately 10,000 MW of coal and nuclear sources, including Diablo Canyon, will be retired by 2025, and the majority of those sources will be replaced by renewable energy (e.g., wind and solar). Mr. Olson stated that renewable sources of energy do not have the same reliability characteristics as that of baseload sources. Thus, E3's findings show that while demand for gas-fired generation has increased in the western region in the last several years, it will remain flat through 2026. Mr. Olson concluded his presentation by indicating that gas-fired generation will continue to serve an important role in ensuring reliable electric service for the foreseeable future.

Eric Eyberg, who is Vice President and Head of Americas Gas and LNG Consulting at Wood Mackenzie, presented on the 2018 WECC Gas-Electric Interface Study.[13] Mr. Eyberg discussed the five N-1 and five N-2 scenarios analyzed by the study team. Under all N-1 scenarios, Aliso Canyon was presumed to be out of service. The largest economic impact scenario was a major pipeline outage in the Desert Southwest and Southern California region and had a low probability of occurring. This event was estimated to have an approximately $30 billion economic impact. When the researchers reinserted Aliso Canyon into the model at approximately 30 percent capacity, it fully mitigated the unserved energy and 75 percent of the unmet spinning reserves. Mr. Eyberg then presented higher probability scenarios: a freeze-off was presumed along with some N-2 assumptions such as low hydro or California wildfire transmission constraints. In the base case, this scenario resulted in $600 million of economic impacts. Mr. Eyberg noted that a physical flow model showed that adding Aliso Canyon at 30 percent capacity fully mitigated the disruption. Results showed that resilient demand combined with less capacity can lead to regional events, not just local ones. The study also highlighted the lack of firm transportation capacity on interstate pipelines held by California's gas-fired electric generators, which is driven by regulations around curtailment and priority of service. Mr. Eyberg asserted that reconciling and improving gas-electric coordination and strategic investment will be key to managing demand fluctuations and lack of flexible capacity to provide fuel assurance.

[13] The study can be found here: https://www.wecc.org/Reliability/Western%20Interconnection%20Gas-Electric%20Interface%20Study%20Public%20Report.pdf.

In response to Scoping Memo Issue 1a, Mr. Eyberg discussed the recommendations shown in Figure 10.

Figure 10: WECC Study Recommendations to Reconcile and Improve Gas/Electric Coordination

	Recommendations	Benefits
Resource Adequacy Accounting	• Report all firm contracts and explicitly link to power plants served in IRP process and other firm reserve reports	• Allows for more robust planning processes and fuel assurance transparency especially as gas and power capacity dynamics tighten
Curtailment Priorities	• Re-visit classification of electric generation as "non-core" end-use • Designation of plants critical to grid reliability as core end-use	• Ensuring that critical power plants are not the first to be curtailed allows for additional flexibility for compensation via transmission
Improved Regional Coordination	• Conduct regional contingency planning exercises led by WECC to prepare for a number of disruption scenarios	• Maximizes compensation ability for utilities across the Western Interconnection
Forecasting & Execution	• Require intra-day LDC core load balancing to ensure fair OFO/penalty implementation • Additional clarity around interstate pipeline curtailment protocol	• Higher accountability for prior-day forecasting allows easier utility operation • Explicit interstate curtailment protocols allow for better contingency planning
Gas-Electric Day Mismatch	• Split weekend nomination period into daily blocks, resulting in a 7-day nomination cycle	• A feasible step for both gas and electric sides that would minimize response lead times over the weekend period
Strategic Regional Investments	• Invest in regional mitigation solutions, including renewables/batteries, demand side response, gas infrastructure, and maintain dual-fired generation flexibility	• Meeting the future needs of the BPS in the Western Interconnection reliably and at low cost will require a portfolio of mitigants

Source: Wood Mackenzie, E3, Wood Mackenzie – Western Interconnect Gas-Electric Interface Study (2018)
1. NERC Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System published March 2020

5.1.2 Southwest Gas

Steve Williams, Director of Systems Planning, spoke on behalf of Southwest Gas Corporation. Mr. Williams presented historical average gas usage from 2014 to 2018 in the PG&E, SoCalGas, and SDG&E territories derived from the 2019 California Gas Report Supplement, which showed that in aggregate, approximately 63 percent of total annual average demand was attributable to noncore customers. He then shared a chart that showed that a significant amount of interstate pipeline capacity is up for renewal during 2020-2045. For example, the chart showed that approximately 3 Bcf of daily capacity is up for renewal in 2020. If pipelines do not sell firm capacity to California customers, they will look for opportunities to sell capacity upstream of California. Mr. Williams used the El Paso Pipeline, which is selling approximately 1.4 Bcf of capacity to Mexico, as an example of this dilemma. He cautioned that a lack of willingness by California's electric generators to enter into long-term contracts will lead to interstate service volatility.

Mr. Williams then discussed three potential solutions to address these issues. One suggestion is to require CPUC-regulated utilities to secure long-term, firm interstate capacity contracts (e.g. 10-year term with gradual capacity decline). Another suggestion is to require long-term California border and Citygate contracts, similar to interstate capacity contracts. The third suggestion is for the CPUC to hold workshops with interstate pipeline operators to address potential service reliability issues that may be caused by contracting behavior.

5.1.3 Crossborder Energy Presentation

Tom Beach gave a presentation on behalf of Calpine Energy. Mr. Beach started his presentation by making several points about California's competitive gas market. He stated that there is sufficient access to interstate

pipeline capacity and major access to the Western Canadian Sedimentary, Rockies, San Juan, and Permian basins. However, he also noted that although California has 10 Bcf of interstate capacity to the state, the takeaway capacity from the border to the load centers is significantly less at 7 Bcf.
Mr. Beach then showed a chart of CAISO electric generation burner tip prices and gas market prices from January 2017 to June 2020 to illustrate the impact of intrastate issues, such as recent pipeline outages and the constraints on Aliso Canyon. SoCalGas electric generation burner tip prices experienced spikes as a result of these constraints.

Mr. Beach then discussed the issue of reservation charges for interstate pipelines and backbone pipelines within California. These contracts require a straight fixed variable or a modified fixed variable rate design. Thus, transportation charges are paid as a fixed monthly reservation charge.

He explained that it only makes sense for gas-fired electric generators to hold firm capacity if the generator has a high load factor and is assured of a baseload market for the electricity produced. However, gas demand from electric generators is variable throughout the course of the day and fluctuates seasonally, peaking in the summer, and also fluctuates due to hydro conditions. Mr. Beach asserted that existing gas infrastructure can handle hourly fluctuations in electric generators' gas demand. Moreover, recent decisions have expanded gas balancing and reserve services, which should help meet daily and hourly fluctuations. As renewables grow on the electric system, there is a premium placed on flexible generation to meet ramps. However, if an electric generator is locked into a fixed-capacity gas contract, it is difficult to operate flexibly without experiencing exorbitant costs.

Mr. Beach highlighted another reason why Calpine Energy does not believe electric generators should be required to hold firm transportation capacity—there will be a significant reduction in demand for gas-fired generation in order to meet California's carbon reduction goals.. He maintained that it is more important to maintain the existing infrastructure. Furthermore, generators in the CAISO market have several incentives to remain reliable. He stated that Resource Adequacy contracts require gas-fired generators to hold reliable gas supply in order to be able to respond to demand on a peak day. Must-Offer obligations also compel generators to be ready to produce.

He ended by stating that if there is a desire to deem certain electric generators as "core" or "essential," then there needs to be long-term electric contracts to ensure that the costs from holding interstate pipeline firm capacity could be recovered.

5.1.4 Summary of Q&A
There were three questions for the panelists. The first question was directed to Wood Mackenzie/E3 and asked what type of model was used for the N-1 and N-2 scenarios, which assumed Aliso Canyon was operating at 30 percent capacity. Mr. Eyberg responded that they used a physical flow model rather than a hydraulic model. The second question was also for Wood Mackenize/E3 and asked whether the modeling assumed that off-system deliveries on the SoCalGas system are on an interruptible basis only. Mr. Eyberg indicated that the modeling did not assume off-system deliveries to end-users disrupted outside of California but focused on whether the addition of Aliso Canyon would allow displacement of gas, which it did. The third question was for CrossBorder Energy and asked whether they believe hourly gas takes by electric generators will increase, decrease, or stay the same as more variable resources are added to the grid. Mr. Beach said he expects to see daily and hourly fluctuations in the future and that it will largely depend on how much storage is built on the electric system. Mr. Olson from E3 chimed in and stated that storage will mitigate some of the hourly fluctuations but not all of it. He believes average daily throughput will decrease but peak use will not necessarily decrease. Mr. Beach agreed with this statement.

5.2 Reliability in All Timescales: Getting Gas to Electric Generators

5.2.1 CAISO

Delphine Hou spoke on behalf of CAISO. In response to Scoping Memo Issues 1.b. and 1.c., Ms. Hou stated that there is a lot of close coordination with gas utilities in the day-ahead timescale, which includes coordination about demand expectations, contingencies, preparing for ancillary services, and a gas burn report with granular information. Ms. Hou indicated that there has been a lot of progress in the past couple of years to coordinate and fine-tune existing processes in light of recent pipeline outages and the constraints on Aliso Canyon. If multiple days of low solar generation can be captured in the day-ahead timeframe, the information is incorporated into the gas burn report and shared with gas utilities. However, in the real-time timescale, the process of sharing information becomes more complicated as fluctuations related to the supply fleet, transmission issues, or other unexpected issues may arise.

5.2.2 Southern California Generation Coalition

Catherine Yap and Norman Pederson presented on behalf of the Southern California Generation Coalition. Ms. Yap started her presentation by discussing the various drivers of gas demand in the winter and summer. Ms. Yap stated that electric generator loads can drive the evening peaks in the summer. Then, Ms. Yap discussed gas demand during the winter and provided the week of January 13, 2019, as an example to illustrate how gas demand can fluctuate throughout a winter day in relation to solar output. The two graphs (see Figure 11) on Slide 44 illustrate that the morning ramp during the winter is steep due to heating demand. However, Ms. Yap noted that on January 14, 2019, which had a small amount of solar output, mid-day gas demand did not drop due to the higher electric generation load. Then, Ms. Yap discussed electric generation loads in the week of May 19, 2019, which saw significant solar output, shown in Figure 12: EG Loads in May Vary by Day and by Hour. This was a cool week, and there were steep heating ramps during the first four days of the week, which tapered off as weather warmed. Gas sendout during the middle of the day generally decreased because solar output was high. There was less of an impact on gas sendout during this week due to high solar penetration.

Figure 11: EG Loads in January Vary by Day and by Hour

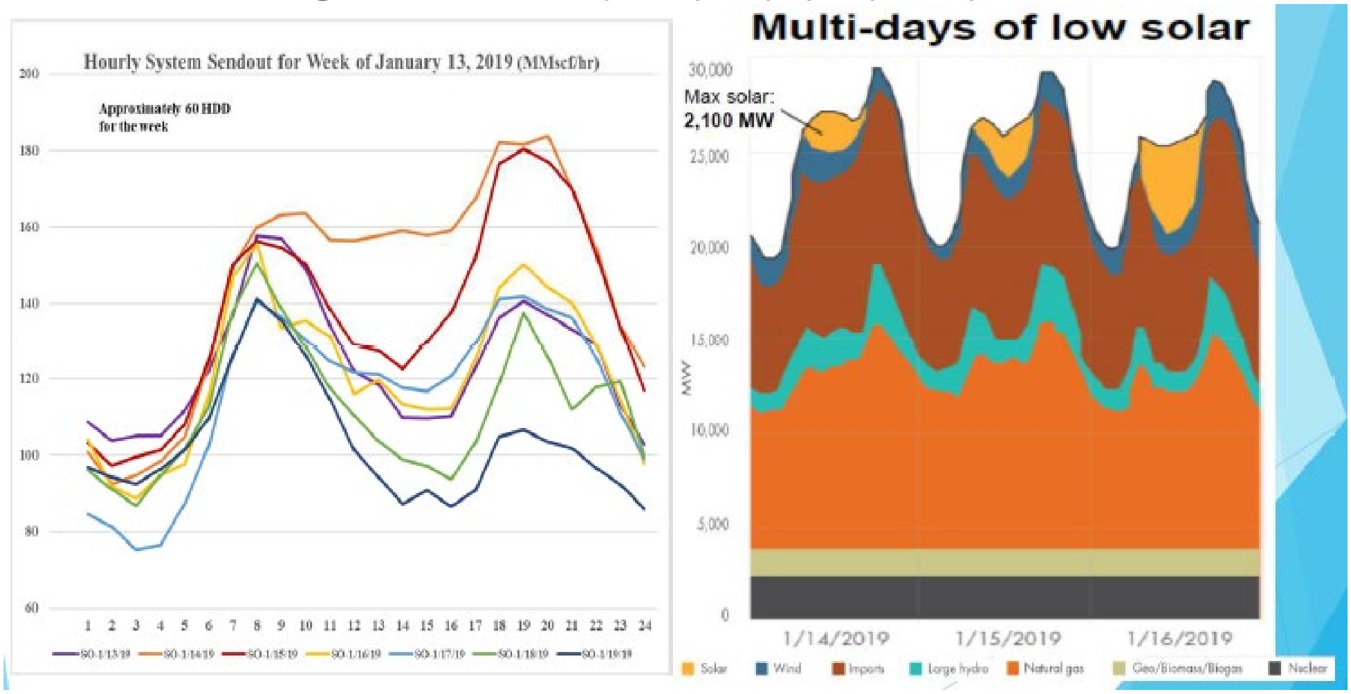
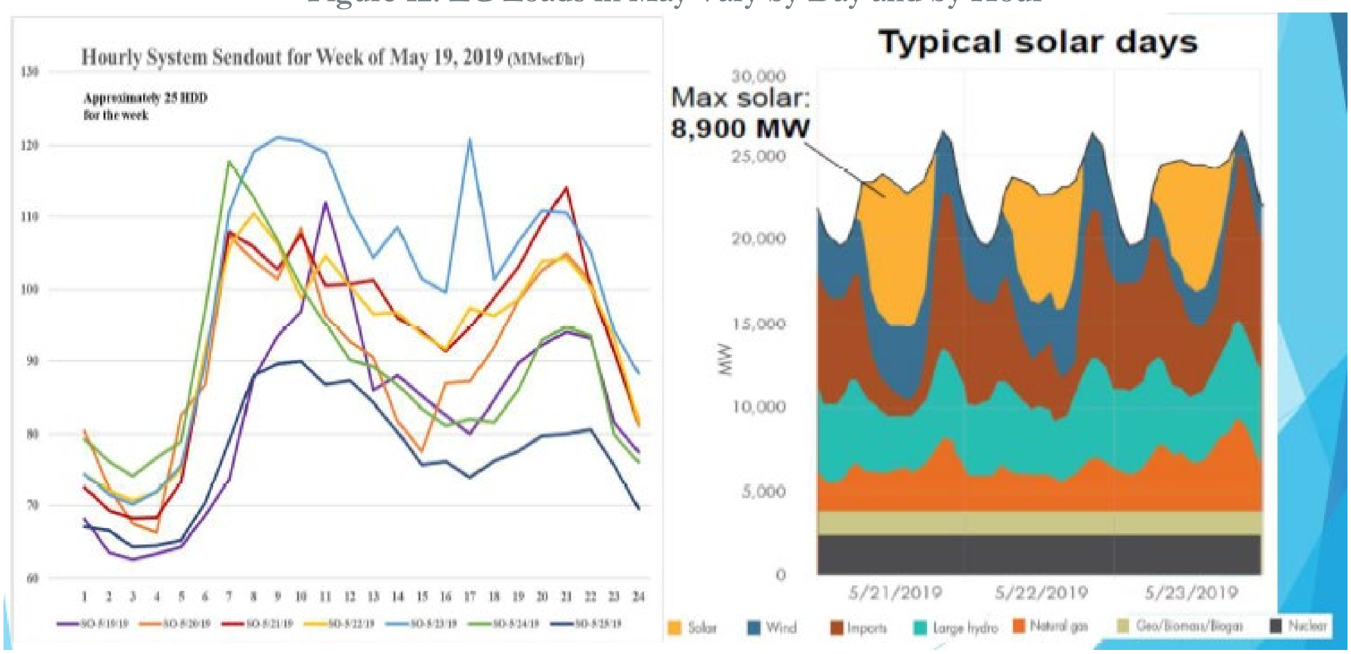


Figure 12: EG Loads in May Vary by Day and by Hour

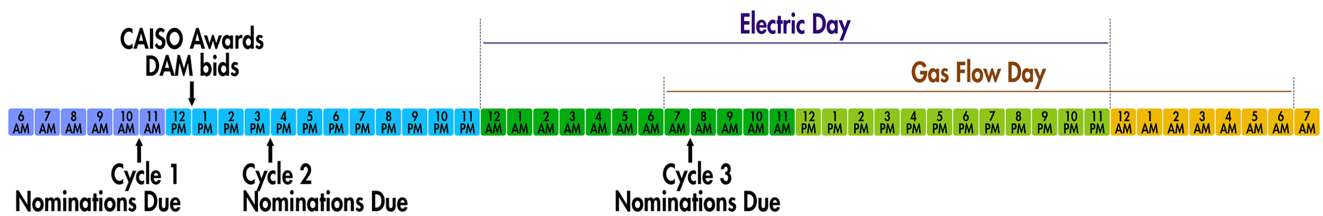


Mr. Pederson started his presentation by indicating that interstate supply to SoCalGas' receipt points is ample, and generators do hold capacity on interstate pipelines. In addition, suppliers who sell gas at the SoCal Border or Citygate typically hold firm interstate pipeline capacity as well. Thus, Mr. Pederson concluded that interstate pipeline capacity is not an issue. Then, he discussed SoCalGas' firm Backbone Transportation Service (BTS) and stated that the capacity offered from October 2020 to September 30, 2023, is very limited (2,715 MMcfd in 2020 vs. 3,875 MMcfd in 2017) and vastly below the capacity that is available upstream of the SoCalGas system. Mr. Pederson then stated that linepack on SoCalGas' system is a relatively small resource (200 MMcfd) and, therefore, the system cannot rely much on linepack to respond to the needs of electric generators.

Mr. Pederson asserted that gas markets for intraday nomination cycles are thin, particularly on high demand days. California gas buyers, such as electric generators, find that sellers are reluctant to sell in the intraday cycle because receipt point capacities may be cut ("windowed") by the System Operator to prevent over-pressurization of the backbone transmission system. If SoCalGas cuts receipt point capacities during Intraday nomination cycles, then SCGC recommends that shareholders should credit the associated amount of reservation charges to the nominating customer's account. Mr. Pederson stated that this proposal may reduce SoCalGas' use of "windowing" and enhance participation in the Intraday Cycle markets. Instead of cutting nominations for firm BTS transportation service, Mr. Pederson maintained that SoCalGas should use the high operational flow order tool to address over-pressurization concerns. Another tool that can help electric generators is a liquid daily published price for each day of the week. Mr. Pederson stated that it is not within the CPUC's jurisdiction to implement this change, but it would be a useful market reform. Currently, nominations for Saturday, Sunday, and Monday are made on Fridays. For electric generators, loads fluctuate significantly, and a liquid daily published index would help these customers manage their flowing supply.

Ms. Yap then continued the presentation by discussing the mismatch between the electric and gas market schedules as shown in Figure 13 below. The electric day is from midnight to midnight, while the gas day is from 7:00 am to 7:00 am. CAISO's awards for the Day-Ahead Market are awarded at 1:00 pm, after the Gas Day Cycle 1. Thus, infra-marginal generators only have an opportunity to schedule during Cycles 2-5 because they are higher on the dispatch order and likely have to wait until they receive a Day-Ahead Award. Cycle 2-5 markets have thinners margins and create price volatility issues for those generators.

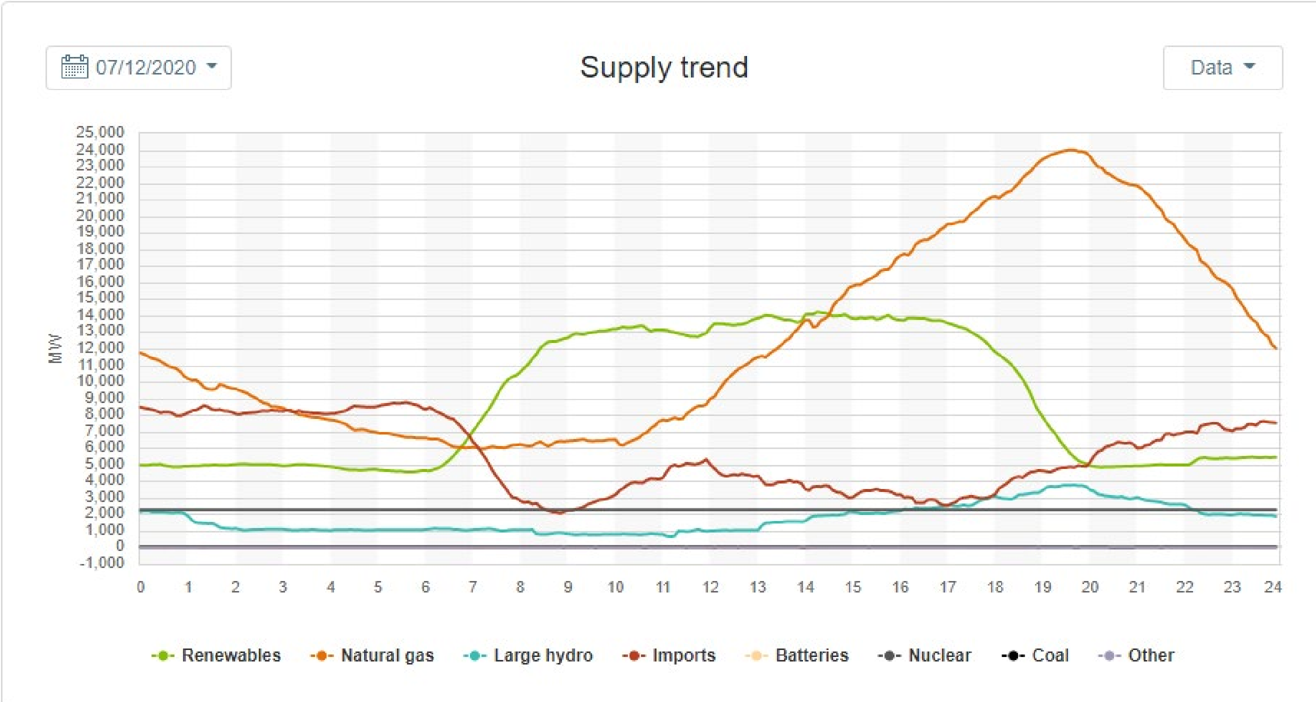
Figure 13: Mismatch Between CAISO Day Ahead Market Awards and Gas Nomination Cycles



5.2.3 Independent Energy Producers

Jan Smutny-Jones represented Independent Energy Producers (IEP). First, Mr. Smutny-Jones briefly mentioned the various industries that IEP represents, including utility-scale solar, wind, geothermal and biomass programs. Then, Mr. Smutny-Jones discussed the shift in the role of natural gas from being a baseload resource to providing the bulk of reliability needs during the highest demand hours. To illustrate this point, Mr. Smutny-Jones shared the July 12, 2020 CAISO Supply Trend chart (Figure 14). He stated that July 20 was a hot day with limited amount of imports. The gas fleet ramped down in the morning and rapidly ramped back up in the middle of the day as demand increased (about 40,000 MW of demand), but renewables stayed flat which required approximately 24,000 MW of thermal generation to fulfill the peak demand.

Figure 14: CAISO Supply Trend 7/12/2020



Mr. Smutny-Jones asserted that the electric generation fleet needs a stable Resource Adequacy mechanism to maintain a multi-year competitive market that will address the shifting peak and seasonal ramping needs. This mechanism would provide a basis for electric generators to make necessary capital expenditures at their facilities and plan for future gas needs. Then, Mr. Smutny-Jones discussed what happens during multiple days of low solar generation. He discussed January 1, 2019, to illustrate this issue. On this winter day and similar others, over 15,000 MW of resources were needed in a three-hour period, which was met by natural gas generation and imports. Historically, California's electric market was summer peaking due to hot weather, but he pointed out that recently the market has two peaks (one-hour net load ramp and three-hour net load ramp), with ramps frequently driven by a lack of solar when the sun goes down. Over the last nine to 10 years, the increase in ramping needs both on a one-hour and three-hour basis shows an upward trend.

Then, Mr. Smutny-Jones discussed maintenance and outages on the SoCalGas system to highlight the importance of making sure intrastate infrastructure meets California's needs. He reiterated that he does not believe gas generators should buy long-term contracts if they don't have a need for it. With regard to having uniform pipeline operating procedures, Mr. Smutny-Jones stated that there is no need for it. In conclusion, IEP believes the current regulatory scheme is served well by interstate markets, and the focus should be on intrastate issues. Prematurely closing gas plants would be a mistake since data shows they are needed into 2030 and maybe 2045.

5.2.4 California Council on Science and Technology

Dr. Jane Long spoke on behalf of the California Council on Science and Technology (CCST), a nonpartisan, nonprofit organization established by the legislature. Dr. Long discussed some of the key findings of the 2018 CCST report Long-Term Viability of Underground Natural Gas Storage in California.[14] First, Dr. Long mentioned some of the reasons for having gas storage, which include injecting gas into storage to

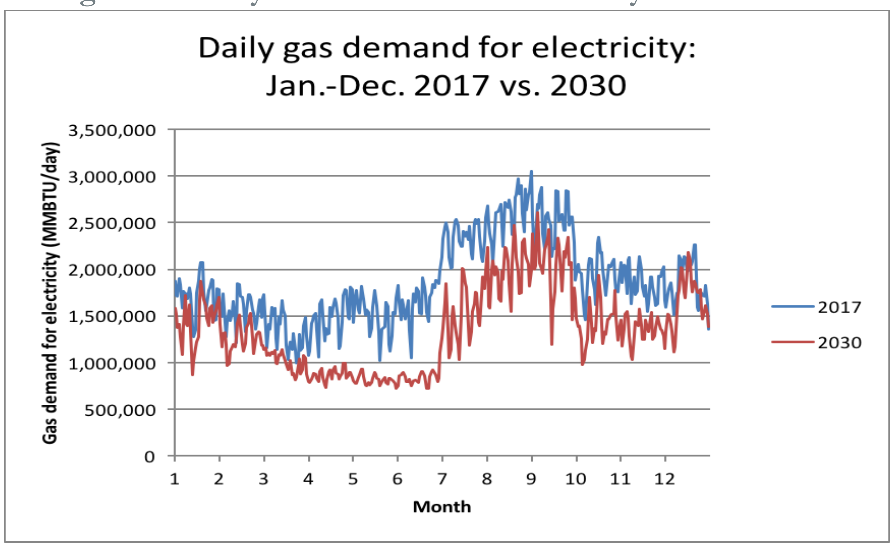
[14] The report can be found here: https://ccst.us/reports/long-term-viability-of-underground-natural-gas-storage-in-california-an-independent-review-of-scientific-and-technical-information/.

prepare for winter use, meeting winter peak day demand, supporting hourly changes in demand, and serving as back-up for renewable generation. Additionally, gas storage has been needed to respond to emergencies related to weather and wildfires. Lastly, Dr. Long stated that gas storage serves a financial function through seasonal and short-term arbitrage.

The study found that if a gas system can meet peak winter demand, storage can also serve other important functions such as intraday balancing and creating an in-state stockpile.

The CCST study includes an assessment of the idea of adding new pipelines to replace storage. Dr. Long advised that this would have its own set of risks, cost approximately $15 billion, and shift the risk of supply not meeting demand to upstream of California. In conclusion, she asserted that there is no "silver bullet" to replace underground gas storage in the near term. Winter gas demand is caused by demand for heat, and California as yet has no statewide policy to electrify residential heating. Dr. Long shared the following chart, in Figure 15, which shows that while gas demand for electric generation will decrease by 2030 during much of the calendar year, gas use in the winter months will not change. There are some scenarios that estimate a decrease in annual gas demand by 11 to 22 percent, but this is not enough to reduce the need for gas storage as the need for storage will be largely driven by peak gas use in the winter. [15]

Figure 15: Daily Gas Demand for Electricity: 2017 and 2030



The presentation covered another important observation of the CCST study—there is much less renewable generation available in the winter. Dr. Long warned that electrifying heat to lower emissions while simultaneously generating more electricity from renewables may create a "perfect storm." She asserted that an integrated approach is needed to ensure reliability during multi-day periods of low output from wind and solar. In 2030 and beyond, California will need some type of low greenhouse gas fuel such as biomethane, synthetic natural gas, or hydrogen to address multiday or seasonal supply-demand imbalances. According to Dr. Long, however, these new technologies will not take away from the need for gas storage.

5.2.5 California Hydrogen Business Council

Dr. Jeffrey Reed, Chief Scientist of Renewable Fuels and Energy Storage at UC Irvine, spoke on behalf of the California Hydrogen Business Council. Dr. Reed stated that electro-fuels, such as hydrogen or synthetic methane, are an intersection between the gas and electric systems. These resources are flexible and can be

[15] CCST Report on Long-Term Viability of Underground Natural Gas Storage in California at 632: https://ccst.us/wp-content/uploads/Full-Technical-Report-v2_max.pdf

generated following a load curve mirroring solar and wind production and then be turned down or off later in the afternoon/early evening to reduce the ramp rate.

Dr. Reed asserted that the prevalence of renewable gaseous fuels needs to be considered in Track 1A and Track 1B of this proceeding, as well as Track 2. He then shared a map of the SoCalGas system to discuss the results of a flow simulation analysis that looked at the flow dynamics of injecting hydrogen at various receipt points. He stated that once the ultimate blend limit of hydrogen is determined, then electrolytic hydrogen can be combined with CO2 to make synthetic methane, which would not have the same supply limitations as hydrogen alone. Then, Dr. Reed discussed the RESOVLE resource planning model, which includes a feature that can make renewable gaseous fuel available in the form of biomethane in certain quantities and at certain price points. Dr. Reed ran his own scenarios, modifying the price assumptions in RESOLVE. Preliminary results show that at $16/MMbtu and $8/MMbtu renewable hydrogen or methane would reduce the need for battery storage and reduce the amount of thermal capacity that needs to be retired. Dr. Reed shared that several studies found renewable hydrogen could reach $8/MMBtu in the near future.

5.2.6 California Environmental Justice Alliance

Deborah Behles spoke on behalf of the California Environmental Justice Alliance (CEJA), a statewide, community-led alliance representing environmental justice communities. Ms. Behles first discussed the likelihood of California experiencing multiple days of low solar or wind generation and said this phenomenon is not a common occurrence in the state. She cited a study from the National Oceanic and Atmospheric Administration (NOAA), which shows that some California cities have high annual solar penetration rates (Redding, 88 percent; Los Angeles, 73 percent; and Sacramento, 78 percent). She also stated that California has high average windspeeds throughout the state. With regard to the concept of "dark doldrums" referenced in the Track 1B agenda, Ms. Behles cited the 2019 Southern California Edison *Pathway 2045* study, which looked at the 2018-19 winter season and concluded that an extensive period of low solar production "would be a relatively rare occurrence as most storm events did not have a sufficient impact to reduce solar production by that much."[16]

Then, Ms. Behles discussed why continued reliance on natural gas for an extraordinary event is not the answer. Some of the reasons given include statutory goals, such as SB 100, greenhouse gas emissions, air pollution, and economic considerations. She emphasized that communities do not want to pay for two systems (gas and electric), as the cost will fall most on those least likely to afford it. Lastly, Ms. Behles discussed possible solutions, such as forecasting of extraordinary events in advance, demand-side management, energy storage, and hydro and geothermal resources, etc., as options to help move away from natural gas.

5.2.7 Summary of Q&A

The first question was for Norman Pederson and asked whether allowing electric generators to buy gas at a liquid daily published index for each day of the week would provide environmental and ratepayer benefits. Mr. Pederson said there would be significant ratepayer benefits as this would allow electric generators to purchase gas at the lowest possible price instead of relying on purchasing gas at one index price for several days at a time.

The second question was for CEJA and asked what the economic consequences would be, if dark doldrums occur as a rare event and there is not enough gas to prop up the system. Ms. Behles stated that pipeline

[16] The study can be found here: https://www.edison.com/home/our-perspective/pathway-2045.html.

outages and gas system volatility show the importance of having diverse resources to back up the electric system. Dr. Reed added that Caltech researchers published a paper last year analyzing 35 years of weather data to consider this issue.[17] These low renewable days are known to occur and are not statistically insignificant. Mr. Smutny-Jones also responded, stating that he is not against having demand-side resources but from an affordability perspective, we need to plan the gas system around events that could wreak havoc on the economy if there is a lack of sufficient power. He also noted that the gas fleet is highly regulated by local air quality districts and the California Air Resources Board. He cited a study that was done under SB 100, at a time when 45 percent of load was met by natural gas, which showed that less than 2 percent of criteria pollutants came from natural gas. He stated that he believes the impact of natural gas on the environment is overstated, and a lot of gas plants are located in wealthy neighborhoods. Dr. Long responded and said eliminating emissions, not necessarily fossil fuels, is most consistent with SB 100.

The third question was also for CEJA and asked whether the solar penetration data shown on Slide 112 is based on an annual or seasonal basis. Ms. Behles responded that the data is annual.

The fourth question was open to all the panelists and asked whether anyone has studied the costs and benefits of expediting electrification and obviating the need for the gas system. Mr. Smutny-Jones responded that electrification will be a challenge because California will need to maintain the gas system as long as there is some need for gas. Second, he stated that with regard to maintaining affordability, it would be a mistake to prematurely abandon the existing infrastructure. Lastly, Mr. Smutny-Jones noted that it will be difficult to electrify if electrification will increase costs for customers. Ms. Behles then added that the Gridworks report determined that continuing to invest in gas will lead to stranded assets and the brunt of related costs will fall on customers least likely to afford it. Mr. Pederson also chimed in and stated that the pipeline safety enhancement plans already underway will need to be amortized over decades. For this reason, he stated that we need to improve our use of assets and safety investments.

The last question was for all the panelists and mentioned the reduced solar generation, hot weather, and wildfire smoke seen in July 2018. The questioner asked what type of energy source will be used during that type of an outage in the future. There were a variety of answers to this question. Mr. Smutny-Jones mentioned the importance of the gas fleet in responding to this type of an event; Dr. Reed discussed fuel cells and microgrid proliferation; and Ms. Behles emphasized the need for local, resilient solutions.

5.3 Gas System Constraints and Electric Price Volatility: Potential Solutions

5.3.1 SoCalGas/SDG&E

Michelle Dandridge, Manager of Transmission and Storage Strategy, and Jonathan Peress, Director of Regulatory Affairs, spoke on behalf of SoCalGas/SDG&E. Ms. Dandridge first discussed the factors contributing to electric price volatility including capacity constraints, market forces, and gas supplies not matching gas demand. Ms. Dandridge specifically pointed to capacity constraints due to pipeline outages and operational restrictions on Aliso Canyon as well as regulatory challenges that affect the construction or repair of infrastructure. With regard to market forces, Ms. Dandridge noted that Backbone Transportation Service holders are not necessarily those with demand on the system. Those with demand on the system have to buy at the Citygate, where there is less liquidity. Other causes of price volatility highlighted by Ms. Dandridge were inaccurate forecasts exceeding gas system capacity, including higher than anticipated

[17] Energy Division staff believe the paper referred to is titled "Role of Long-Duration Energy Storage in Variable Renewable Electricity Systems" https://www.sciencedaily.com/releases/2020/08/200806133513.htm.

demand exceeding system capacity, and unexpected ramps in demand such as those caused by electric generation customers.

Mr. Peress then spoke about the difference between core and noncore load profiles. He stated that the gas market presumes that customers will use gas much the way it is delivered to the system: on a ratable basis of 1/24th of the customer's total daily quantity per hour. However, this is not the case with some noncore customers such as electric generators. These customers may take more or less than the ratable amount, which can cause stress on the SoCalGas system. Noncore customers are able to do this due to SoCalGas' supply contracts plus on-system assets (storage and line pack). Mr. Peress stated that a majority of system costs are allocated to core customers, including the assets relied upon by noncore customers.

The Rule No. 30 tariff provision requires gas deliveries to be "practicable at uniform hourly and daily rates of flow." However, Mr. Peress asserted that electric generators rarely comply with this rule. Rather, intraday variability is increasing with the use of renewables, which causes more ramps up and down on the gas system. Mr. Peress argued that the capability of the gas system to manage intraday ramps provides integrated energy system benefit and value. Mr. Peress presented a table, Figure 16, that showed the maximum deliveries by electric generators to the SoCalGas system (Dth/Hr) to point out that, on some days, electric generator loads can both overpressurize and underpressurize the system.

Figure 16: Deliveries by Electric Generators

Year	Max Volumes (Dth/Hr)	Equivalent Daily Capacity of SCG Backbone to provide the Hourly Capacity (Dth per Day)	Category	Season
2017	147,583	3,541,997	Deliveries to Electric Gen	Summer
2018	120,552	2,893,247	Deliveries to Electric Gen	Summer
2019	118,304	2,839,298	Deliveries to Electric Gen	Summer
2017	63,604	1,526,493	Deliveries to Electric Gen	Winter
2018	53,461	1,283,053	Deliveries to Electric Gen	Winter
2019	62,724	1,505,369	Deliveries to Electric Gen	Winter

He then presented a table with electric generators' non-ratable takes (usage) in 2017-19 to highlight the volatility of electric generators' hourly burn. Between 2017 and 2019, there were more than 1,500 days in which the 84 electric generators on the SoCalGas system used 100 percent of their day's burn in one hour.

Mr. Peress also expressed concern about electric generators' ramp downs, which contribute to the overpressurization of the SoCalGas system. These ramp downs sometimes require SoCalGas to curtail receipts (window) to balance the system. SoCalGas' projections show total takes by gas generators will decrease but that volatility will increase. Mr. Peress concluded his presentation by stating that renewable integration and decarbonization of the energy grid increase unpredictability for both the gas and electric grids; the need for, and value, provided by the gas system's receipt, storage and delivery services; and the importance of peak hour capability. His concluding slide also suggested a new tariff structure, a proposed "Renewable Balancing Service." Lastly, he stated that the OIR raises equitable cost allocation considerations.

5.3.2 Southern California Edison

Marci Palmstrom, Director of Trading and Market Operations, presented on behalf of Southern California Edison (Edison). She began her presentation by discussing recommendations to achieve electric reliability and lower cost volatility caused by gas supply issues. First, Ms. Palmstrom indicated that electric market timelines should be better aligned with gas schedule timelines, noting that 90 percent of gas supplies are procured before electric generation schedules are known. Second, she advocated for a cost-based voluntary tariff for CAISO-connected electric generators. This tariff would allow gas utilities to optimally plan their daily pipeline and storage operations and establish the cost of gas for electric generators. According to Ms. Palmstrom, gas utilities are in the best position to balance risk and manage gas imbalances. As an example, she noted that SoCalGas has access to storage assets not available to noncore customers.

While the amount of gas-fired electric generation will decline over time, Ms. Palmstrom asserted that the state will continue to depend on it to integrate renewables and maintain reliability. Ms. Palmstrom echoed Tom Beach in stating that long-term fixed price contracts for interstate pipeline capacity are not feasible because there is less opportunity for bid recovery in the CAISO market. The last part of Ms. Palmstrom's presentation was related to the issue of uniform pipeline operating procedures. She stated that there may be better opportunity for uniformity of curtailment and OFO rules. For example, in PG&E's territory, curtailment is voluntary and there is a mechanism to compensate for gas imbalances. However, on the SoCalGas system, curtailment is mandatory. With regard to OFO rules, Ms. Palmstrom recommends maintaining the new summer OFO rules adopted by SoCalGas until its gas system is in a fully operational state.

5.3.3 CAISO

Delphine Hou spoke on behalf of CAISO. Ms. Hou discussed three factors that should be considered with Issue 2 of Track 1B, which focuses on ways to decrease electric price volatility related to gas supply issues. First, she argued that the previous SoCalGas OFO rules did not necessarily change electric generator behavior but had cascading effects on the electric market. She maintained that it is important to ensure that penalty or scarcity pricing actually results in useful price signals. Second, she noted that the CAISO's market is one market and pricing is marginal, so to the extent there is different pricing and regional variation, ultimately that will manifest as a uniform marginal price in the electric market. If gas prices are different in the north and the south, then that will impact the electric market as well. Lastly, she stated that parties should seek mechanisms to balance gas system today and respond to volatility in the future.

5.3.4 Utility Consumers Action Network

Dr. Eric Woychik spoke on behalf of the Utility Consumers Action Network. Dr. Woychik stated that UCAN supports a supply and demand-side strategy to tackle gas system constraints. He also recommended that this proceeding be integrated with other proceedings. UCAN recommends the following supply-side measures: 1) Curtailment of new residential gas hookups on the SoCalGas system; 2) Removal of the GCIM; 3) Creation of a working group to develop gas supply contracts for parts of the system where there is a lack of gas-on-gas competition. For the third recommendation, he advocated for contracts to hedge supply deficiencies should be defined and gas storage minimums should be required for intraday fluctuations and low renewable days. Dr. Woychik stated that he cannot say whether this suggestion is feasible. In addition, UCAN recommended the closure of Aliso Canyon as the gas field will require more money to maintain safe operations. Lastly, he maintained that current circumstances suggest uniformity of pipeline operating procedures are not feasible or desirable. SoCalGas' pipeline operating orders need to be further updated to ensure adequate gas is available when renewables are low, such as during a rainy season while also recognizing the potential for regulatory arbitrage.

5.3.5 Summary of Q&A

The first question was for SoCalGas/SDG&E and asked what changes to Tariff Rule No. 30 are required in order to avoid infrastructure changes. Mr. Peress responded that the gas market is premised on ratable receipts and takes. For this reason, there needs to be a commonsense approach to compensate for the costs and value of gas system services and reflect those in electric system. The second question was also for SoCalGas/SDG&E and asked whether SoCalGas can provide data that shows that the increase in intraday variability is due to electric generator loads and not core customer loads. Mr. Peress said that SoCalGas can provide this information.

The next few questions were directed to Edison. The first question asked how electric generators would compete with one another if supplied with gas from a common tariff. Ms. Palmstrom said that this tariff would allow electric generators to pay the same price for gas. In response, Mr. Peress stated that this approach has been rejected across different parts of the country because offering a flat price for supply undercuts competition and hurts ratepayers as a result. Dr. Woychik suggested that the use of the tariff could be limited and not applicable across all electric generators. The second question asked if Edison believes all noncore customers should select a cost-based voluntary tariff that Edison has proposed for electric generators and whether access to core storage will diminish quality of service for core customers. Ms. Palmstrom replied that the concept for this tariff is as a mechanism to keep the gas and electric systems integrated, and it would only apply to electric generators. A follow-up question asked whether Edison is willing to become a core customer and pay core service rates to take advantage of core assets. Ms. Palmstrom stated that this is not what Edison is proposing. Edison is proposing availability of resources not currently available to noncore customers. Costs associated with these assets would be recovered through a tariff. The next question asked whether Edison has a program to use hedge instruments to mitigate price volatility. Ms. Palmstrom stated that Edison is in the market on a regular basis, has a variety of long-term contracts, and uses hedging mechanisms too.

The next question was directed to CAISO and asked whether a change in cost allocation for electric generators would impact CAISO and reliability. Ms. Hou responded that there could be reliability impacts, but she did not know whether pricing itself would lead to issues. If reliability issues are signaled through pricing, CAISO wants those signals to be effective.

Then, a question was posed to SoCalGas/SDG&E regarding whether the comparison of core and noncore customer costs is misleading because core customer costs also include a large amount of distribution costs that do not serve electric generators. SoCalGas/SDG&E's presentation did not parse costs between transmission and distribution services. Mr. Peress responded that SoCalGas provides support to ramps up and down, which are financed by core customers through their storage assets.

The next question was also posed to SoCalGas/SDG&E and asked whether SoCalGas is implying that noncore customers do not pay for balancing services. Mr. Peress and Ms. Dandridge responded that noncore customers benefit from core assets because only 8 Bcf of inventory is dedicated to the balancing function. The last question was also for SoCalGas/SDG&E and asked how noncore customers could get more access to storage especially in the summer and leave sufficient gas in storage for core customers in the winter. Ms. Dandridge replied that if there is more access to Aliso Canyon than the current maximum authorized capacity of 34 Bf, then more inventory can be dedicated to the Unbundled Storage Program. (as shown in the recent TCAP).

5.4 Potential Uniformity of Pipeline Operating Procedures

5.4.1 Pacific Gas and Electric Company

Roger Graham presented on behalf of PG&E. First, Mr. Graham discussed the gas nomination process on the PG&E system. There are five gas nomination cycles. The gas usage day is from 12am-12am, but the gas supply day is from 7am-7am. Mr. Graham indicated that this variance benefits customers because by the time the gas flow day starts, customers have seven hours of known usage, and the gas usage day ends before the gas flow day ends. On the balancing side, customers are permitted to balance supplies and usage on a monthly basis; volumes exceeding the 5 percent tolerance band need to be resolved the following month.

With regard to OFOs, PG&E forecasts the balance between supply and demand five times a day. Customers have access to this information via Pipe Ranger and can view the Operating Data and identify when the inventory is trending toward an OFO. Mr. Graham explained that the inventory in the system is a proxy for PG&E to manage the maximum and minimum operating pressures to serve system load. Too much inventory could force the system to exceed maximum pressures and shut down compressor stations. On the other hand, too little inventory would mean there is inadequate pressure to serve all loads. PG&E uses the OFO tool to remedy high or low OFO conditions. PG&E has five OFO stages. The Stage 3 OFO noncompliance charge is $5/Dth and jumps to $25/Dth for a Stage 4 OFO. PG&E strives to call an OFO early in the day during the first Timely Cycle when customer have more control over scheduling.

Mr. Graham then discussed the differences between PG&E's OFO rules and those of SoCalGas. He stated that PG&E is open to updating their current OFO rules to mimic SoCalGas' winter OFO rules. However, he believes SoCalGas' summer OFO rules are unproductive since the highest noncompliance charge is set at $5/Dth, which could be less incentive for customers to come into compliance. This lack of incentive could potentially lead to an emergency OFO. Mr. Graham went into further detail about the differences between the PG&E and SoCalGas OFO rules. PG&E's OFO rules are designed around pipeline inventory limits; whereas SoCalGas' rules are based on storage withdrawals and injection.

Another difference Mr. Graham noted between the systems are the curtailment rules. For PG&E, local curtailments of noncore customers are used to resolve capacity constraints in localized sections of their backbone pipeline system. A local curtailment may be implemented when local system temperatures are expected to drop below Cold Winter Day temperatures. Local noncore customers may be required to curtail gas usage to ensure local core demands are met. These events are rare; as an example, Mr. Graham stated that the most recent event was called in December 2013 due to unusually cold weather. Then, he shared a table with a summary of Low OFO occurrences from 2018 through June 2020. The table shows that only five Stage 4 low OFOs were called during that period, all of which occurred in 2019. If PG&E'S OFO structure resembled that of SoCalGas' winter OFO structure, it's possible that lower stage OFOs with less expensive penalties could have been called. Mr. Graham concluded the presentation by indicating that PG&E's OFO rules appear to be working effectively but that PG&E is open to increasing the number of OFO stages for alignment with SoCalGas' winter rules. He also acknowledged that PG&E's physical pipeline constraints and operating conditions are different than SoCalGas; therefore, it would also make sense for the OFO rules to be different.

5.4.2 SoCalGas/SDG&E

Paul Borkovich presented on behalf of SoCalGas/SDG&E. Mr. Borkovich stated that there is a lack of uniformity on both systems due to operational considerations and pipeline configurations. According to Mr. Borkovich, prior to SoCalGas implementing winter balancing rules, SoCalGas experienced issues with insufficient supply on their system. Adoption of low OFO procedures in June 2015 temporarily aligned balancing procedures between the two utilities, addressing observed reliability impacts to SoCalGas in previous years resulting from misalignment. However, changes to the OFO stages and noncompliance charges in D.19-05-030 in May 2019 again brought the two companies' rules out of alignment. Mr. Borkovich then discussed SoCalGas' specific OFO rules. A high OFO is declared if, on the day prior to the Gas Day, the system forecast of storage injection required for balancing exceeds the injection capacity allocated to the balancing function. A low OFO is declared, if, on the day prior to the Gas Day, the system forecast of withdrawal required for balancing exceeds the withdrawal capacity allocated to the balancing function. OFOs are only declared on the Evening Cycle and Intraday 1 cycle on the day before the Gas Day.

D.19-05-030, issued in May 2019, adopted two different OFO structures for the winter and summer months. The OFO noncompliance charge for Stage 4 and Stage 5 low OFOs from June 1 to September 30 is capped at $5/Dth. This temporary structure is adopted through October 31, 2021. Mr. Borkovich discussed the key differences between the two OFO noncompliance structures, shown in Figure 17 below. The adopted $5 per Dth ceiling on the summer noncompliance charges has not been tested since implementation of the decision. The subsequent implementation of the revised Aliso Canyon Withdrawal Protocol in July 2019 has dampened low OFO activity and potential price spikes, obviating the need for Stage 4 OFOs, at least under the conditions seen since its implementation.

Figure 17: SoCalGas OFO Penalty Structures

OFO Noncompliance Structure June 1 – September 30		
Stage	Daily Imbalance Tolerance	Noncompliance Charge ($/Dth)
1	Up to +/-25%	0.25
2	Up to +/-20%	1.00
3	Up to +/-15%	5.00
4	Up to +/-5%	5.00
5	Up to +/-5%	5.00 plus G-IMB daily balancing standby rate
EFO	Zero	50.00 plus G-IMB daily balancing standby rate

OFO Noncompliance Structure October 1 – May 31		
Stage	Daily Imbalance Tolerance	Noncompliance Charge ($/Dth)
1	Up to +/-25%	0.25
2	Up to +/-20%	1.00
3	Up to +/-15%	5.00
3.1	Up to +/-15%	10.00
3.2	Up to +/-15%	15.00
3.3	Up to +/-15%	20.00
4	Up to +/-10%	25.00
5	Up to +/-5%	25.00 plus G-IMB daily balancing standby rate
EFO	Zero	50.00 plus G-IMB daily balancing standby rate

The revised Aliso Canyon Withdrawal Protocol authorized SoCalGas to withdraw gas from Aliso Canyon if any of four conditions are met. Mr. Borkovich stated that the implementation of the revised Withdrawal Protocol had a definite impact on the number of low OFOs called in 2019 as shown in Figure 18 below. Mr. Borkovich indicated that it probably helped customers avoid low OFOs on 44 of the 57 days that it was used. There were 13 days when a low OFO was not avoided; for two of these events, a low OFO had already been declared on an earlier cycle.

Figure 18: Aliso Canyon Withdrawal Protocol Events

	Aliso Canyon Withdrawal Protocol Events	Low OFO Declared
Condition Met	57	13
Condition 1 – Cycle 1	36	9
Condition 1 – Cycle 2	15	2
Condition 1 – Cycle 3	5	2
Condition 4	1	

Mr. Borkovich concluded his presentation by stating that curtailment rules should remain utility-specific based on operational differences between the respective utility systems. OFO rules exist to incentivize supply delivery in an open market, and the utilities should have similar tools available to respond to market behavior. Lastly, the temporary low OFO rules have been unnecessary in light of the Withdrawal Protocol and could hinder SoCalGas' ability to incentivize deliveries during times of system stress and should not be continued as a "price mitigation" tool.

5.4.3 Southern California Generation Coalition

Catherine Yap and Norman Pederson presented on behalf of the SCGC. Mr. Pederson stated that SCGC agrees that for operational reasons there are different rules on the different systems, and those should continue. Before 2014 and 2015, there were no low OFO rules for SoCalGas. D.15-06-004 created low OFO rules for SoCalGas. In that decision, the CPUC expressed concern that noncore was leaning on the core. Mr. Pederson stated that the SoCalGas OFO rules originated so that noncore customers would not lean on core customers. Then, Mr. Pederson stated that it seemed as if core customers were relying on noncore customers as a result of the forecasting rules in place prior to D.19-08002 (core balancing decision). D.19-08-002, which went into effect on April 1, 2020, requires core to balance to estimated actuals rather than a forecast.

Then Mr. Pederson discussed the actual OFO rules for PG&E and SoCalGas and the key differences between the two. Mr. Pederson said the $5 cap on summer OFO penalties in the SoCalGas service territory prevents market anticipation of high OFO penalties from driving up SoCal Citygate prices for gas during electric generators' peak summer burn period. For the winter, the SoCalGas schedule's gradual increase is more favorable than PG&E's simplified schedule. The SoCalGas approach permits the utility to more precisely fit the noncompliance charge and the stage of the OFO to Citygate market conditions. He stated that he agrees that PG&E has a lot of storage on its system and that it may not be necessary to change PG&E's OFO structure.

Ms. Yap then discussed the price spikes of July 2018. The basis for Citygate and Border prices was slightly above the OFO penalty level. However, in 2019, there was a dampening in price response that aligns with the new OFO penalty structure and the revised Withdrawal Protocol. She then stated that the Withdrawal Protocol eliminated some OFOs entirely. The revised OFO structure also contributed to the price dampening effect. Ms. Yap asserted that the evidence shows that the revised OFO structure for SoCalGas has contributed to reducing the Citygate-Border price differential. Lastly, she recommended that if there is to be any change in OFO protocols, PG&E should move in the direction of SoCalGas's more graduated winter OFO schedule.

5.4.4 Summary of Q&A

The first question was related to Aliso Canyon and what the impacts to electric generators would be if the storage facility is shut down. Mr. Borkovich said there would be a repeat of the July 2018 price spikes and a trend towards tighter balancing rules.

The second question was whether select use of negotiable gas supply contracts could be applied to generators expected to have market power in the event that Aliso Canyon is shut down. Mr. Borkovich stated that the capacity to serve customers would be diminished, and there would be major restrictions to service, especially to noncore customers. Mr. Pederson also cited the most recent TCAP decision, which approved a methodology for allocating storage inventory and injection, and withdrawal capacity if Aliso Canyon's maximum authorized inventory is increased above or decreased below the currently authorized capacity of 34 Bcf. For this reason, Mr. Pederson agreed with Mr. Borkovich that the balancing rules would have to be tightened if Aliso Canyon is shut down.

The next question asked the panelists about their thoughts on allowing full use of Aliso Canyon in the near term but adopting policies to drive down gas demand in the long term. Mr. Borkovich stated that SoCalGas is supportive of that approach. Mr. Graham noted that most of the costs to make Aliso Canyon compliant with CalGEM regulations to convert wells to tubing-only flow have been incurred. For this reason, Mr. Graham stated that it does not make sense to not use the storage facility to its full extent as not doing so creates economic hardship for all customers.

5.5 Summary of Final Q&A

At the end of the day, there was a final question-and-answer period in which participants could ask questions on any of the day's topics. The first question asked Dr. Woychik about his recommendation to curtail new residential gas connections and whether that idea can be balanced with customer choice. Dr. Woychik responded and said he currently works with a variety of companies to develop large-scale residential distributed energy solutions, which is an economic choice for customers.

Then, Diane Moss with the California Hydrogen Business Council reiterated some of Dr. Reed's remarks and stated that there is growing consensus that gaps will exist when there is not enough sunshine or wind. She asserted that decarbonized hydrogen is a cost-effective way to provide reliable fuel from renewable sources and should be integrated into long-term gas planning.

The next question was related to Dr. Long's comment about the need to focus on reducing overall emissions and not focusing on eliminating fossil fuels. The question asked the panelists how we can make cost-effective tariff changes in this rulemaking while keeping in mind the advice from Dr. Long. Ms. Yap said there are mechanisms in place to address the societal costs of emissions, such as cap and trade regulations. Ms. Behles stated that SB 350 requires emissions reductions from gas generators as there are high health and societal costs associated with any increases in emissions. Ms. Yap noted that transportation contributes heavily to emissions and that electric generators are heavily regulated for air quality purposes. Ms. Beheles followed-up by agreeing with Ms. Yap and adding that in some cities, power plants can be the single biggest stationary source of emissions.

The last question was related to the GCIM. Under the GCIM, SoCalGas is incentivized to make profitable secondary market sales that can benefit core customers but may increase electric costs for core and noncore electric customers. The question asked whether it is appropriate for SoCalGas to raise their competitors' costs in this manner? Mr. Pederson responded and said this is a valid concern, and core customers are not the only group benefitting under this mechanism, but also shareholders. Mr. Pederson reiterated that the Unbundled Storage Program is closed due to the limitations on Aliso Canyon and the only other option for noncore customers is purchases in the secondary market. Ms. Yap chimed in and highlighted that high Citygate purchases made by marginal generators have amplified electric prices.

STAFF RECOMMENDATIONS

1 TRACK 1A

Scoping Memo Issue 1: What are SoCalGas' and PG&E's current system capabilities?

a. Do PG&E and SoCalGas have the requisite gas transmission pipeline and storage capacity to meet the demand for an average day in a one-in-ten cold and dry-hydroelectric year for their respective backbone gas transmission systems and peak day demand for their combined backbone gas transmission and gas storage systems?
b. Do PG&E and SoCalGas have the requisite gas transmission pipeline and storage capacity to meet the local transmission standards adopted in D.06-09-039?
c. How should the Commission respond to a gas utility's sustained failure to meet minimum transmission system design standards?

Recommendations: In D.06-09-039, Findings of Fact 7, the local transmission standards adopted for SoCalGas/SDG&E set the standard as a 1-in-35-year event for core customers and 1-in-10-year event for firm noncore customers. For PG&E, the local transmission standard is one event in 90 years for core customers and one event in three years for noncore. At the time of this writing, staff finds that PG&E has the requisite gas transmission pipelines and storage capacity to meet an average day demand in a 1-in-10 cold and dry-hydroelectric year and their abnormal peak day demand as forecasted in the 2020 California Gas Report. Furthermore, PG&E meets the local transmission standards adopted in D.06-09-039.

As stated in Mr. Bisi's presentation, SoCalGas/SDG&E can meet the 2020 1-in-35 extreme peak day demand of 3,490 MMcfd, which results in all noncore customers being curtailed. However, currently, SoCalGas/SDG&E are not able to meet the 2020 1-in-10-year cold day demand of 4.9 Bcf.

In response to Scoping Memo Issue 1.c., Indicated Shippers suggested that utilities should be required to share in the cost of repair or the CPUC should reduce the utility's return on equity. Additionally, TURN suggested that utility shareholders absorb a percentage of the cost of repairs on a graduated scale, with the percentage borne by shareholders increasing with the length of time that the design standard is not met. TURN suggested that "if the utility fails to keep at least 80% of its backbone capacity available over any rolling three-month period, the company be required to absorb 25% of the cost of repairs needed to restore the needed capacity. If the 80% level cannot be met over a rolling six-month period, the shareholder portion would increase to 50%, with 75% sharing at nine months and 100% shareholder responsibility if the problem persists for over one year."[18] Staff agrees with TURN that there should be consequences for failure to meet the design standards. However, given the challenges of permitting and construction in remote, protected areas where many of the transmission pipelines lie, staff proposes that the nine-month criterion in PU Code Section 455.5 be used as a *guideline* for determining the duration after which shareholders begin to absorb a percentage of the cost of repairs.[19] Note: In the discussion below, staff recommends a design standard that includes both pipeline and storage assets. If such a proposal is accepted, the consequences for not meeting the standard would need to apply to both backbone transmission and storage, rather than just backbone, as TURN suggests. Staff recommends that parties provide comment on the nine-month criterion

[18] TURN's response to ALJ's Ruling Seeking Comments, Dated August 14, 2020, pg. 5.
[19] PU Code Section 455.5 states "In establishing rates for any electrical, gas, heat, or water corporation, the commission may eliminate consideration of the value of any portion of any electric, gas, heat, or water generation or production facility which, after having been placed in service, remains out of service for nine or more consecutive months, and may disallow any expenses related to that facility." Staff emphasizes that the recommendation is to use this as a guideline.

proposal as well as the appropriate proportion of costs that ratepayers and shareholders should cover under a design standard that includes both pipeline and storage assets.

Scoping Memo Issue 2: Are the existing natural gas reliability standards for infrastructure and supply still adequate? If not, how should they be changed?

a. Should the Commission establish uniform reliability standards for PG&E and SoCalGas, rather than allow the utilities to continue to use different standards?
b. Temperature forecasts for Northern California indicate that between 2018-2035, the average temperature during December and January will be between two to nine percent above the 20-year average. Will the current reliability standards overstate the capacity that gas utilities must maintain?
c. Gas-fired generators comprise approximately 40 percent of electric supply during the summer months. Temperature trends forecast warmer summers in California; thus, should the Commission establish separate reliability standards for the summer months?

Recommendations:

Issue 2(a): Staff recommends that the CPUC eliminate all current infrastructure design standards and replace them with a 1-in-10-year peak day design standard for both PG&E and SoCalGas/SDG&E that can be met using a combination of flowing pipeline supply and gas storage.

Staff agrees with the Justice Parties' suggestion that PG&E's 1-in-90 Abnormal Peak Day (APD) standard is excessive and recommends that it be eliminated. Staff goes farther, however, and recommends that all but the 1-in-10-year peak day standard be terminated. Staff's goal in making this recommendation is to increase both simplicity and clarity without compromising reliability. Although various parties argued that the utilities are different and therefore should have different standards, staff does not agree. The proposed standard merely establishes an interval of expected reliability: 10 years. The utilities are free to optimize their differing systems as they see fit in order to meet that standard.

Specifically, staff recommends that the minimum system design standard be equivalent to each utility's 1-in-10-year cold day demand forecasted in the most recent California Gas Report. Under this standard, the utilities are responsible for having enough capacity to meet both core and noncore demand on the coldest day in 10 years. The standard can be met with a combination of flowing pipeline gas and storage, and the proportion of the standard that is met with each resource shall be left to each utility to determine.

The 1-in-10-year peak day standard has the advantage of already being in use by both utilities. With the adoption of PG&E's Gas Transmission and Storage (GT&S) application in D.19-09-025, the CPUC supported a System Supply Reliability Standard. Within the System Supply Reliability Standard, core and electric generation demand is calculated using the 1-in-10-year cold day demand methodology used in the California Gas Report. Staff recommends that PG&E continue to utilize the System Supply Reliability Standard and update each demand component according to the latest basis for value available, as shown below and adopted in D.19-09-025.

Line No.	Demand Component	Volume (MMcf/d)	Basis for Value
1	Core	2,493	1-day-in-10-year demand
2	Electric Generation	928	1-day-in-10-year demand
3	Industrial	522	Average daily winter demand
4	Off-system and shrinkage	123	Firm delivery obligations; calculated shrinkage
5	Inventory Management	300	Per PG&E proposal
6	Reserve Capacity	250	Per PG&E proposal
7	Total Supply Reliability Demand	4,616	

SoCalGas and SDG&E's current 1-in-10-year cold day demand forecast should continue to serve as a design standard. In PG&E's Track 1A slack capacity presentation, Mr. Brown stated that other factors, such as confidence interval levels for the reliability standards and minimum design pressure, need to be considered along with the temperature recurrence intervals. Staff recommends that PG&E provide further details and elaborate on these factors.

Staff considered maintaining the 1-in-35 year extreme peak day design standard, in which all but core customers are assumed to be curtailed, or recommending the modified 1-in-35 year standard proposed by SoCalGas/SDG&E in which some customers currently classified as noncore are reclassified as core. However, staff believes that the 1-in-35-year standard is unnecessary. Data in the 2020 California Gas Report indicates that core 1-in-35-year demand will always be lower than the 1-in-10-year cold day demand. Furthermore, staff is concerned that eliminating the 1-in-10-year peak day standard and using only a modified 1-in-35-year standard does not provide enough certainty to noncore customers. Noncore customers do not pay for, and should not expect, the same level of reliability as core customers. However, staff believes that noncore customers should have some reasonable degree of certainty that they will be able to get the gas they need. A one outage in 10 years standard is common in the energy industry and seems reasonable in this case. Lastly, even absent a 1-in-35-year standard, the reliability of core customers can still be protected by their place in the curtailment order.

Staff points out that the supply standards for core customers established in D.04-09-022 were not discussed during the workshops, and recommends that the CPUC and parties to this proceeding give consideration to whether the supply standards should be revisited as well.

Although not explicitly mentioned in the Scoping Memo, staff agrees with the points made by Mr. Reisinger and PG&E, in that a reliability definition should be adopted that would guide the creation of "clear and concise minimum design standards." The current capacity utilization standard is not defined in a way to identify when a utility is not in compliance. Rather, it is a planning tool to determine when a utility should consider expanding its capacity."[20] Arguably, the formally independent gas and electric systems have become inextricably intertwined since D.06-09-039 was issued. California's natural gas infrastructure is relied upon as fuel supply for a significant portion of California's electric generators. The role of California's natural gas infrastructure is especially important during times of low renewable generation. Staff calls attention to two recent cautionary tales: the five days of mandatory gas curtailments of electric generators during winter of 2018-19 and the two rotating power outages of August 2020. Given these recent events, staff recommends a reliability definition and minimum design standards that recognize the electric system's current level of reliance on the natural gas system to support California's overall energy system.

> **Suggested Reliability Definition:** Gas reliability is a measure of the gas system's capacity and ability to deliver uninterrupted service. It represents the ability to supply gas and the capacity to transport it in amounts sufficient to meet customer demand.

Note that *capacity* represents the quantity of gas the physical assets of the system can deliver (and is typically an absolute measure) while *ability* represents the utility's power, skill, or competence to deliver service (often a relative measure, which can include non-physical assets/rules/expertise/skills, etc.). *Ability* also implies that a gas system is resilient and therefore, able to continue delivering service after an unexpected failure of the system's most critical component.

[20] PG&E's response to ALJ's Ruling Seeking Comments, Dated August 14, 2020, pg. 2.

Issue 2(b): Staff recommends relying on data from *California's Fourth Climate Change Assessment* (Fourth Assessment) or the most recent Assessment available in the future, which can be found on Cal-Adapt.org. In subsequent California Gas Reports, the gas utilities should be required to review the Fourth Assessment or the latest Assessment available and incorporate relevant data to adjust their cold day demand forecasts. The gas utilities should also describe how the Assessment has been incorporated and what adjustments were made to the California Gas Reports based on the latest Assessment.

Issue 2(c): Staff recommends that a summer reliability standard not be established. The July 7, 2020, workshop and subsequent comments did not demonstrate a need for a summer reliability standard.

Scoping Memo Issue 3: Should gas utilities maintain a specific amount of slack capacity or additional infrastructure in excess of the amount of backbone transmission and storage capacity necessary to meet the existing one-in-ten cold and dry year reliability standard? If so, how much and under what conditions?

Recommendations: In D.06-09-039, the decision that discussed slack capacity requirements, the CPUC found that, "[i]n order to determine the amount of slack capacity that should be available in the case of emergencies, it is necessary to identify, at least in a general sense, the nature of the emergencies which the excess capacity would protect."[21] PG&E provided seven "functions of emergency capacity" as part of its proposal in R.04-01-025:

1. To moderate gas prices through gas-on-gas competition.
2. To ensure that gas customers do not become captive to a limited choice of supplies and rising prices during times of constraint.
3. To ensure that gas at the California border is available to compete against any other supply source that might attempt to charge a commodity price higher than the otherwise available marginal supply.
4. To guard against the impact of dry hydroelectric years on price and availability.
5. To respond to increasing gas demand for electric generation.
6. To moderate prices during some pipeline and storage facility emergency events (such as a sudden loss of capacity), as well as during periods of short-term variability of demand.
7. To rely on long-term planning to avoid the high commodity prices that may result if the utility were to wait for the market to decide when there is a need for more capacity.

Staff believes the seven functions are still largely applicable today.

The decision then stated that the CPUC wanted to "encourage a balanced reliance on stored gas, because of the seasonal difference in gas demand and price, because there is a substantial storage capability, and because stored gas is an important physical hedge."[22]

Given the balanced reliance on stored gas and the availability of substantial storage capability at the time, only considering backbone capacity in the slack capacity requirement made sense. However, with Aliso Canyon's maximum allowable inventory at 34 Bcf, SoCalGas now operates with a 42 percent reduction in storage inventory, and it is unclear what Aliso Canyon's future inventory will be. Staff does not have a specific slack capacity recommendation, at this time, but believes that the PG&E and SoCalGas/SDG&E systems should be able to meet their minimum system design standards after an unexpected failure of a critical component in each gas system. Staff invites party recommendations on slack capacity requirements. Staff is also aware that the findings in Order Instituting Investigation to consider the future of Aliso Canyon (I.17-02-002) will play a role in SoCalGas/SDG&E's determination of excess capacity on their system.

[21] D.06-09-039, pg. 21.
[22] Ibid., pg. 22.

During the workshop, Mr. Reisinger explained that PG&E currently reports slack capacity as capacity utilization, whereas SoCalGas/SDG&E reports slack capacity as a reserve margin. Staff questions the necessity of PG&E and SoCalGas/SDG&E reporting slack capacity in biennial advice letters, as currently required, because the methodologies (below) use average day demand, rather than cold day demand. However, if an advice letter continues to be required, staff recommends that the advice letters should also include a confidential section identifying the top three critical system components and the amount of capacity each supports.

Current Slack Capacity Methodologies:

$$Reserve\ Margin\ = \frac{Firm\ Daily\ Receipt\ Capacity\ - Average\ Daily\ Demand}{Average\ Daily\ Demand}$$

$$Capacity\ Utilization = \frac{Average\ Daily\ Demand}{Backbone\ Capacity}$$

Note: Firm Daily Receipt Capacity refers to backbone capacity.

Scoping Memo Issue 4: Will transportation of gas to the planned Energía Costa Azul LNG export facility, owned and operated by an affiliate of SoCalGas, over the proposed expanded North Baja pipeline which is the subject of FERC Docket No. CP20-27, impact reliability and prices in SoCalGas' service territory and beyond? If so, what measures should SoCalGas undertake to assure reliability, and how should such costs be recovered?

Staff notes that further information is needed regarding available capacity at Ehrenburg/Blythe and pipeline operations at the interconnections to answer these questions. SoCalGas's representation of 2.3 Bcfd of available delivery capacity from El Paso Natural Gas Ehrenberg lacks detail as to how the figure was derived.[23] SCGC's figure of 2.985 thousand dekatherms per day (MDthd) includes 953 MDthd from North Baja,[24] ostensibly flowing south to north from Mexico, which the North Baja line is technically capable of but is contrary to the predominate north-to-south flows on North Baja,[25] which would be increased with the stated operational goals of the North Baja Xpansion Pipeline. SoCalGas' acknowledgment that on days with Southern System minimum flows of over 0.7 Bcfd with a "hypothetical 0.48 Bcfd decrease in supply from EPNG" the System Operator would need "additional tools to maintain Southern System reliability"[26] and that 78 days over the three year period from April 2017 to March 2020 the Southern System minimum exceeded 0.7 Bcfd[27] suggests that there are potential reliability issues associated with North Baja.

SoCalGas listed five available tools for the System Operator to maintain Southern System Reliability: (1) spot market purchases at Southern Zone receipt points for subsequent sale at the SoCal Citygate; (2) Memoranda in Lieu of Contract between the Gas Acquisition Department and the System Operator for coverage of the Southern System Minimum attributable to bundled core customers; (3) Seasonal Base Load

[23] SoCalGas/SDG&E Joint Post-Workshop Comments, p. 31 ("El Paso response to a verbal query in June 2020").
[24] SCGC Response to Energy Division Questions, dated August 14, 2020, p. 19 and Appendix.
[25] See Abbreviated Application For a Certificate of Public Convenience Necessity by North Baja Pipeline, LLC ("Application"), FERC Docket No. CP20-27, p. 4
[26] SoCalGas/SDG&E Joint Post-Workshop Comments, p. 32
[27] Id.

transactions to secure preset daily Southern Zone receipts during winter and summer peak periods; (4) discounted BTS contracts applicable to Southern Zone receipt points; and (5) issuance of a Request for Proposals seeking additional tools.[28] Staff believes these tools, and other potential measures such as those proposed by UCAN[29], deserve further evaluation by both staff and SoCalGas/SDG&E.

Staff notes that Scoping Memo Issue 5, regarding whether the updated reliability standards result in additional costs, is still pending.

2 TRACK 1B

Scoping Memo Issue 1: Should the Commission consider whether potential fluctuations in natural gas demand combined with potentially insufficient firm interstate gas pipeline contracts held by California customers could pose risks to interstate pipeline capacity services?

a. What measures, if any, can be taken to ensure interstate pipeline transportation capacity reliability?
b. What measures, if any, can be taken to ensure that gas needs of electric generators are met during hourly and intraday fluctuations?
c. What measures, if any, can be taken to ensure that gas needs of electric generators are met during multiple days of low renewable generation?

Recommendations:
There was a lack of consensus amongst the panelists on how to address the issues under the purview of Scoping Memo Issue 1. Southwest Gas offered that a lack of willingness to enter into long-term contracts would lead to interstate service volatility. On the other hand, Crossborder Energy indicated that it only makes sense for gas-fired electric generators to hold firm capacity if the generators have a high load factor and are assured there is a baseload market for the electricity produced, which is currently not the case.

Wood Mackenzie discussed some of the WECC Gas-Electric Interface Study recommendations on how to reconcile gas and electric coordination issues. One recommendation from the study is to consider reclassifying certain electric generators that are critical to grid reliability as equivalent to core customers. This recommendation suggests that the reclassified customers could then have access to storage rights and firm interstate capacity contracts. While appealing, staff is unsure of whether there is presently enough storage capacity in the SoCalGas service territory to accommodate core heating demand while also accommodating the needs of certain electric generators.

The existing reliability standards dictate how much core and noncore demand must be served. Staff agrees with parties, such as the Public Advocates Office (Cal Advocates), that more information must be gathered about the exact problems reclassifying a subset of noncore to core would solve, and the operational and cost impacts. Calpine, Middle River Power, and Independent Energy Producers Association (IEPA) raised the possibility that gas-fired electric generators reclassified as core would incur higher costs than their noncore counterparts, then pass those higher costs on as higher bids into the CAISO market. Furthermore, if one of these generators cleared the CAISO market, all electric customers within the CAISO would be impacted with higher prices. One of the primary reasons this Rulemaking was initiated was in response to the high

[28] Id.
[29] Comments of the Utility Consumers' Action Network To the Questions Posed By Administrative Law Judge Tran In a Ruling July 31, 2020, p. 11 ("If for some reason the Commission were to allow the removal of this 0.48 Bcf/d for the North Baja Xpress Project, SEMPRA should be made to pay for this capacity, and for replacement capacity, including scarcity cost, which would then be allocated to SoCal Gas customers as a rate reduction.").

prices experienced in 2017 and 2018; therefore, the outcomes of this Rulemaking should not result in higher wholesale gas or electricity prices.

SoCalGas indicated in its post-workshop comments that pending a decision in the Order Instituting Investigation to consider the future of Aliso Canyon (I.17-02-002), the utility does not yet know if it has enough storage capacity to accommodate load reclassification. TURN also highlighted this issue in their post-workshop comments by stating that, absent removal of restrictions on Aliso Canyon, there will not be adequate gas storage to serve additional loads that are transferred from noncore to core service. TURN further recommended that if electric generators are reclassified as core customers, the CPUC should work with CAISO to determine the quantity of electric generation gas supply that should be reclassified as core and allow CAISO to determine which electric generation plants will be dispatched. TURN's comments suggest that choosing specific power plants for core designation would be discriminatory and create market power problems.

CAISO made a similar suggestion in its post-workshop comments, stating that it is more important to designate a minimum volumetric flow of gas needed to support electric reliability rather than specific electric generation customers. CAISO explained that this would ensure a minimum level of gas supply for electric generation needs and better align electric needs with gas planning. SCGC also recommended in their post-workshop comments that if a subset of electric generation is designated as core and inventory at Aliso Canyon is increased to meet the new core load, then only electric generation that represents the minimum Southern California electric demand should change to core service.

Staff believes that these suggestions deserve consideration and recommends that the CAISO submit in their comments to this report a proposal that outlines a mechanism for determining the minimum amount of gas supply needed for electric reliability in California and how the CAISO would allocate that gas to electric generators bidding into the market. SoCalGas and PG&E can then provide a response in reply comments indicating whether the utilities have the capacity to accommodate the need. It is important to note that any reclassification of minimum generation on the gas side would require a mechanism on the electric side whereby electric generators are able to recover fixed costs assumed under the core classification.

If SoCalGas is unable to provide core level service for a minimum volumetric flow of gas to support electric reliability at current storage inventories, then as Cal Advocates suggests in their post-workshop comments, a decision on the future of Aliso Canyon will provide insight into whether revising the core and noncore designations is feasible. Reclassifying a specified amount of electric generation under the core classification could help ensure that the gas needs of electric generators are met during multiple days of low renewables generation.

Scoping Memo Issue 2: During 2017 and 2018, the higher than average gas prices at SoCal Citygate caused the price of wholesale electricity to significantly increase. Should the Commission establish contract or tariff terms and conditions or new rules to attempt to decrease the risk of electricity price volatility caused by potential gas supply issues? If so, what terms, conditions or new rules should be considered?

Recommendations:
Southern California Edison argued at the Track 1B workshop that there should be an opportunity to have a cost-based voluntary tariff for CAISO-connected electric generators. This tariff would allow gas utilities to optimally plan their daily pipeline and storage operations and establish the cost of gas for electric generators. SoCalGas/SDG&E indicated that renewable integration and decarbonization of the energy grid increase unpredictability to both the gas and electric grids and increase the need for and value provided by gas receipts, storage, and delivery services. For this reason, it suggested creating a Renewable Balancing Tariff.

In post-workshop comments, several parties, including CAISO, SCE, and UCAN, requested more information related to SoCalGas' tariff proposal. SCE also noted that the tariff should be optional and include assets such as storage and transportation. Furthermore, Calpine stated it is willing to consider multiple levels of balancing service and costs, if supported with operational and cost data. Staff agrees with these comments and recommends SoCalGas and PG&E submit formal analyses outlining a proposal for a Renewable Balancing Tariff in their respective regions and associated costs. In its post-workshop comments, PG&E stated that it has the existing capacities to handle expected intraday ramping requirements. If PG&E does not believe a formal tariff is needed to provide intraday ramping services to their electric generation customers, then its response should provide a detailed reason as to why.

Scoping Memo Issue 3: Should pipeline operating procedures, such as those for curtailments and operational flow orders, be uniform across the state? Would there be any market and reliability impacts if pipeline operating procedures were not uniform?

Recommendations:
Staff believes uniform pipeline operating procedures across both utilities would be prudent where feasible. PG&E expressed some support for this idea during their presentation at the Track 1B workshop as well as in its post-workshop comments. PG&E indicated that it is open to aligning its OFO structure to SoCalGas' winter OFO structure, noting that this alignment may benefit the California gas market by providing clear and consistent price signals. PG&E, however, expressed concerns related to SoCalGas' current summer OFO rules that were adopted in D. 19-05-030, arguing that a maximum cap of $5/Dth could provide less incentive for customers to come into compliance. Several parties expressed support for the idea of some uniform pipeline operating procedures in post-workshop comments, including TURN, SoCalGas/SDG&E, and SCGC. TURN also stated in their post-workshop comments that the CPUC should maintain the current summer OFO penalty structure for SoCalGas unless the CPUC allows unrestricted use of Aliso Canyon. For the foregoing reasons, staff recommends changing PG&E's OFO structure to match SoCalGas' winter OFO structure. Staff also recommends that SoCalGas' winter OFO penalty structure be extended after the rules expire, pursuant to D.19-05-030, on October 31, 2021.

With regard to SoCalGas' summer OFO penalty structure, the revised Aliso Canyon Withdrawal Protocol has played an important role in reducing the number of low OFOs that have been called as well as preventing higher stage low OFOs from being called. Thus, since there have been no instances of a Stage 4 or 5 low OFO last summer or this summer, it is difficult to assess the impact of the revised OFO penalty structure. Staff will assess any impacts from the SoCalGas summer OFO penalty structure should the system reach a Stage 4 or 5 low OFO.

APPENDICES

APPENDIX A

R.20-01-007 Track 1A Workshop: Natural Gas Reliability Standards

July 7, 2020 | 9:30 a.m. – 4:15 p.m. | Remote participation only
Remote Participation Link:
https://cpuc.webex.com/cpuc/onstage/g.php?MTID=e6dedc7ff39c46ddb0cba180c4ac7a368
Toll Call-in: 1-855-282-6330
Meeting Access Code: 146 885 5452 Meeting Password: Gasplanning0

Workshop Purpose: This workshop covers Track 1A of the Assigned Commissioner's Scoping Memo and Ruling, issued on April 23, 2020.[1] This workshop seeks to provide stakeholders with a common understanding of the issues, gather information, and seek feedback. Additionally, workshop participants may begin to develop possible future scenarios and suggest potential solutions.

Intended Outcome: Participants and attendees will have a better understanding of the facts upon which testimony, hearings (if needed), and briefs (if needed) will proceed upon. Energy Division staff will publish a workshop report in September which will provide recommendations or, at a minimum, a range of options for resolving the issues.

WORKSHOP AGENDA

9:30 – 9:40	**Welcome** ALJ Ava Tran Energy Division staff
9:40 – 9:55	**Overview of Existing Natural Gas Reliability Standards** The current natural gas reliability standards were established in a 2004 rulemaking, R.04-01-025, prior to changes to policy goals and infrastructure availability, and most recently in PG&E's 2019 Gas Transmission and Storage Decision, D.19-09-025. Energy Division staff will describe the current standards and how they differ between utilities. **Gregory Reisinger**, Energy Division staff
9:55 – 10:10	**Q&A**
10:10 – 10:30	**Temperature Projections and Demand Trends** According to California's Fourth Climate Change Assessment, climate change continues to increase average summer and winter temperatures and will cause a

[1] The scope of Track 1A can be found in the Assigned Commissioner's Scoping Memo and Ruling here: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M334/K581/334581865.PDF. Question #5 explores the topic of cost recovery and cost allocation. This topic will not be covered in this workshop and will be covered in a future forum.

higher frequency of extreme weather events. Will increasing temperatures and more frequent extreme events change gas demand profiles? (Scoping Memo Issue 2b)

Susan Wilhelm and Cary Garcia, California Energy Commission

10:30 – 10:45 **Q&A**

10:45 – 10:55 **Break**

10:55 – 12:10 **Can the Reliability Standards Be Met? Are They Still Adequate?** (15 mins ach)
PG&E and SoCalGas/SDG&E will discuss their systems' ability to meet the current reliability standards. All participants will provide their views on whether the current standards are still adequate and, if not, how they should be changed considering temperature projections and demand trends. Participants will also provide their views on how the CPUC should respond to a gas utility's sustained failure to meet minimum transmission design standards. (Scoping Memo Issues 1, 1a-c, 2 and 2a)

Roger Graham, **Rick Brown**, and **Richard Beauregard**, PG&E
Jonathan Peress and **David Bisi**, SoCalGas/SDG&E
Jim Caldwell, Center for Energy Efficiency and Renewable Technologies (CEERT)
Dr. Eric Woychik, on behalf of Utility Consumers' Action Network (UCAN)
Maurice Brubaker, on behalf of Indicated Shippers (IS)

12:10 – 12:25 **Q&A**

12:25 – 1:20 **Lunch Break**

1:20 – 1:50 **Is a Summer Reliability Standard Needed?** (15 mins each)
During the summer, the electric grid depends on gas-fired generation to meet its ever-steeper evening ramp. Those generators, in turn, rely on a gas supply that may or may not be available at a moment's notice. In this panel, electricity market and generation experts will share their views on whether the CPUC should establish separate reliability standards to meet the unique challenges of summer. (Issue 2c)

Delphine Hou, California Independent System Operator (CAISO)
Norman Pedersen, Southern California Generation Coalition (SCGC), and **Tom Beach**, Crossborder Energy on behalf of SCGC, Vistra Energy, Middle River Power, and Calpine

1:50 – 2:05 **Q&A**

2:05 – 2:50 **Slack Capacity: Prudent or Wasteful?** (15 mins each)
In D.06-09-039, the CPUC concluded that the utilities' then-current slack capacity margins of between 11 and 25 percent were adequate but did not set an official standard similar to the N-1-1 electric standard. In D.19-09-025, the CPUC authorized PG&E to establish slack capacity, or "reserve capacity," to address significant unplanned outages. Does the gas system require a certain level of slack capacity to result in just and reasonable gas costs? (Issue 3)

Roger Graham, PG&E
David Bisi, SoCalGas/SDG&E
Catherine Yap, on behalf of Southern California Generation Coalition and Indicated Shippers

2:50 – 3:05	**Q&A**
3:05 – 3:15	**Break**
3:15 – 3:30	**Proposed North Baja Xpress Expansion Project, FERC Docket CP20-27: Impacts on California** SoCalGas/SDG&E will provide a brief overview and analysis of the impact of the proposed North Baja XPress Project to serve the Energía Costa Azul LNG export facility on supply availability and the market within their service territories. If there are supply constraints and price increases associated with increased transportation to serve Energía Costa Azul, an affiliated company of SoCalGas, what measures should be taken to bear such costs or prevent such constraints? (Issue 4) **Paul Borkovich**, SoCalGas/SDG&E
3:30 – 3:45	**Q&A**
3:45 – 4:10	**Final Comments and Q&A (Open to All)**
4:10 – 4:15	**Closing Remarks** Energy Division staff

Note: It is expected that one or more CPUC Commissioners may attend and participate in the workshop. One or more advisors to the CPUC Commissioners, as well as other decision-makers, may also be in attendance. The agenda will be publicly noticed on the CPUC's Daily Calendar 10 days in advance, so statements made at the workshop will not constitute a reportable *ex parte* contact. The workshop will be recorded. This agenda is subject to change.

Page 3

APPENDIX B

R.20-01-007 Track 1B Workshop: Market Structure and Regulations

July 21, 2020 | 9:30 a.m. – 4:30 p.m. | Remote Participation Only
Remote Participation Link:
https://cpuc.webex.com/cpuc/onstage/g.php?MTID=e91dff6a74860f87b4e26f7335b7cadf6
Toll Free Call-in: 1-855-282-6330
Meeting Access Code: 146 066 7997   Meeting Password: Gasplanning0

Workshop Purpose: This workshop covers Track 1B of the Assigned Commissioner's Scoping Memo and Ruling, issued on April 23, 2020.[1] This workshop seeks to provide stakeholders with a common understanding of the issues, gather information and facts, and seek feedback and input. Additionally, workshop participants may begin to develop possible future scenarios and suggest potential solutions.

Intended Outcome: Participants and attendees will have a better understanding of the facts upon which testimony, hearings (if needed), and briefs (if needed) will proceed. Energy Division staff will publish a workshop report in September that will provide recommendations or, at a minimum, a range of options for resolving the issues.

WORKSHOP AGENDA

9:30 – 9:40	**Welcome** ALJ Ava Tran Energy Division Staff
9:40 – 10:25	**Gas Demand Fluctuation and Interstate Capacity Contracts: Risks and Resolutions** (15 mins each) California's gas-fired electric generators primarily rely on interruptible contracts for interstate transportation services. According to the WECC Gas-Electric Interface Study, the reliability risks inherent in this arrangement were previously mitigated by the flexible capacity of Aliso Canyon. Will the combination of increasingly variable gas demand, interruptible interstate capacity contracts, and lack of flexible supplies pose risks to California? (Scoping Memo Issues 1-1a) **Eric Eyberg**, Wood Mackenzie, and **Arne Olson**, E3 **Steve Williams**, Southwest Gas **Tom Beach**, Crossborder Energy
10:25 – 10:40	**Q&A**
10:40 – 10:50	**Break**

[1] The scope of Track 1B can be found in the Assigned Commissioner's Scoping Memo and Ruling here: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M334/K581/334581865.PDF.

Page 1

10:50 – 12:25	**Reliability in All Timescales: Getting Gas to Electric Generators** (15 mins each) The expansion of intermittent energy resources, such as wind and solar, is currently dependent on the complementary ability of gas-fired generators to meet intraday ramping needs and to generate electricity during the "dunkelflaute" periods in winter when California has very little wind or solar generation for days at a time. Participants will discuss potential measures that can be undertaken to meet the intraday and interday needs of gas-fired electric generators. (Scoping Memo Issues 1b-1c) **Delphine Hou**, California Independent System Operator (CAISO) **Norman Pedersen** and **Catherine Yap**, Southern California Generation Coalition **Jan Smutny-Jones**, Independent Energy Producers **Jane Long**, California Council on Science and Technology (CCST) **Jeffrey Reed**, on behalf of CA Hydrogen Business Council **Deborah Behles**, on behalf of California Environmental Justice Alliance
12:25 – 12:40	**Q&A**
12:40 – 1:35	**Lunch Break**
1:35 – 2:35	**Gas System Constraints and Electric Price Volatility: Potential Solutions** (15 mins each) Participants will discuss whether the CPUC, the CAISO, or market participants themselves should establish new contracts, rules, or tariffs to decrease the risk of electric price volatility in the wake of recent gas supply issues. (Scoping Memo Issue 2) **Jonathan Peress** and **Michelle Dandridge**, SoCalGas/SDG&E **Marci Palmstrom**, Southern California Edison **Delphine Hou**, California Independent System Operator (CAISO) **Dr. Eric Woychik**, Utility Consumers' Action Network (UCAN)
2:35 – 2:50	**Q&A**
2:50 – 3:00	**Break**
3:00 – 3:45	**Potential Uniformity of Pipeline Operating Procedures** (15 mins each) Participants will discuss whether pipeline operating procedures, such as operational flow orders and curtailment rules, should be uniform across the state and whether lack of uniformity has the potential to cause market or reliability impacts. (Scoping Memo Issue 3) **Roger Graham**, Pacific Gas & Electric **Paul Borkovich**, SoCalGas/SDG&E **Norman Pedersen** and **Catherine Yap**, Southern California Generation Coalition
3:45 – 4:00	**Q&A**

4:00 – 4:25	**Final Comments and Q&A (Open to All)**
4:25 – 4:30	**Closing Remarks** Energy Division Staff

Note: It is expected that one or more CPUC Commissioners may attend and participate in the workshop. One or more advisors to the CPUC Commissioners, as well as other decision-makers, may also be in attendance. The agenda will be publicly noticed on the CPUC's Daily Calendar 10 days in advance, so statements made at the workshop will not constitute a reportable *ex parte* contact. The workshop will be recorded. This agenda is subject to change

(END OF ATTACHMENT 1]